APPENDICES

DRAFT

APPENDICES

EVALUATION OF BIOMASS-TO-ETHANOL FUEL POTENTIAL IN CALIFORNIA

A REPORT TO THE GOVERNOR
AND THE
AGENCY SECRETARY,
CALIFORNIA ENVIRONMENTAL
PROTECTION
as directed by Executive Order D-5-99

Gray Davis, *Governor*

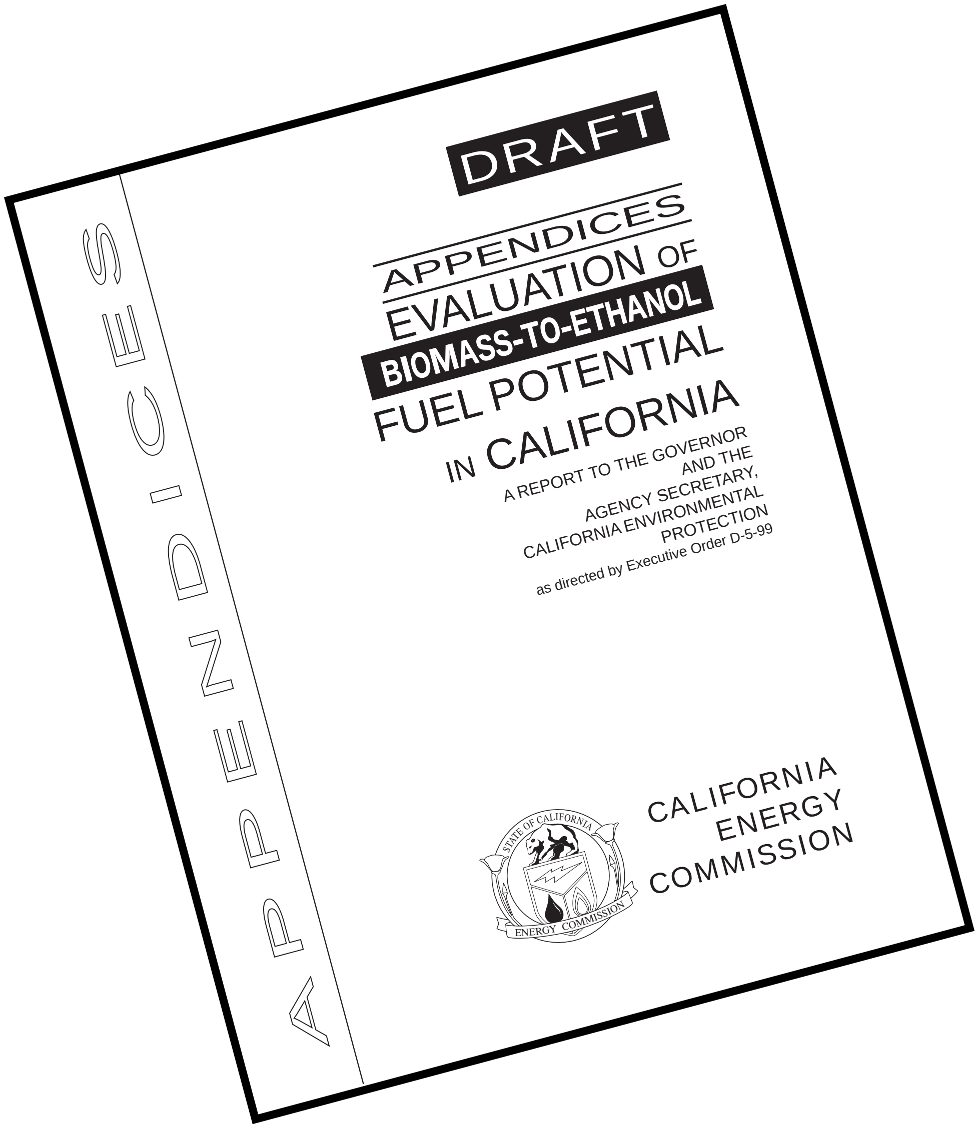
STATE OF CALIFORNIA
ENERGY COMMISSION

AUGUST 1999

CALIFORNIA ENERGY COMMISSION

RESOURCES AGENCY

P500-99-011A



CALIFORNIA ENERGY COMMISSION

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Appendices

Appendix A

Governor Davis' Executive Order D-5-99

Governor Gray Davis

Executive Order

EXECUTIVE DEPARTMENT

STATE OF CALIFORNIA

EXECUTIVE ORDER D-5-99
by the
Governor of the State of California

WHEREAS, the University of California prepared a comprehensive report on the "Health and Environmental Assessment of Methyl Tertiary-Butyl Ether (MTBE)" which has been peer reviewed by the Agency for Toxic Substances and Disease Registry and the Unites States Geological Survey and other nationally recognized experts;

WHEREAS, the University of California report was widely available for public review and written comment, including hearings in northern and southern California to receive public testimony;

WHEREAS, the findings and recommendations of the U.C. report, public testimony, and regulatory agencies are that, while MTBE has provided California with clean air benefits, because of leaking underground fuel storage tanks MTBE poses an environmental threat to groundwater and drinking water;

NOW, THEREFORE, I, GRAY DAVIS, Governor of the State of California, do hereby find that "on balance, there is significant risk to the environment from using MTBE in gasoline in California" and, by virtue of the power and authority vested in me by the Constitution and statutes of the State of California, do hereby issue this order to become effective immediately:

> 1. The Secretary for Environmental Protection shall convene a task force consisting of the California Air Resources Board, State Water Resources Control Board, Office of Environmental Health Hazard Assessment, California Energy Commission and the Department of Health Services for the purpose of implementing this Order.

2. On behalf of the State of California, the California Air Resources Board shall make a formal request to the Administrator of the U.S. Environmental Protection Agency for an immediate waiver for California cleaner burning gasoline from the federal Clean Air Act requirement for oxygen content in reformulated gasoline.

3. The California Environmental Protection Agency shall work with Senator Feinstein and the California Congressional Delegation to gain passage of Senate Bill 645. This legislation would grant authority to the Administrator of the U.S. Environmental Protection Agency to permanently waive the Clean Air Act requirements for oxygen content in reformulated gasoline to states such as California that have alternative gasoline programs that achieve equivalent air quality benefits.

4. The California Energy Commission (CEC), in consultation with the California Air Resources Board, shall develop a timetable by July 1, 1999 for the removal of MTBE from gasoline at the earliest possible date, but not later than December 31, 2002. The timetable will be reflective of the CEC studies and should ensure adequate supply and availability of gasoline for California consumers.

5. The California Air Resources Board shall evaluate the necessity for wintertime oxygenated gasoline in the Lake Tahoe air basin. The Air Resources Board and the California Energy Commission shall work with the petroleum industry to supply MTBE-free California-compliant gasoline year around to Lake Tahoe region at the earliest possible date.

6. By December 1999, the California Air Resources Board shall adopt California Phase 3 Reformulated Gasoline (CaRFG3) regulations that will provide additional flexibility in lowering or removing the oxygen content requirement and maintain current emissions and air quality benefits and allow compliance with the State Implementation Plan (SIP).

7. In order that consumers can make an informed choice on the type of gasoline they purchase, I am directing the California Air Resources Board to develop regulations that would require prominent identification at the pump of gasoline containing MTBE.

8. The State Water Resources Control Board (SWRCB), in consultation with the Department of Water Resources and the Department of Health Services (DHS), shall expeditiously prioritize groundwater recharge areas and aquifers that are most vulnerable to contamination by MTBE and prioritize resources towards protection and cleanup. The SWRCB, in consultation with DHS, shall develop a

clear set of guidelines for the investigation and cleanup of MTBE in groundwater at these sites.

9. The State Water Resources Control Board shall seek legislation to extend the sunset date of the Underground Storage Tank Cleanup Fund to December 31, 2010. The proposed legislation would increase the reimbursable limits for MTBE groundwater cleanups from $1 million to $1.5 million.

10. The California Air Resources Board and the State Water Resources Control Board shall conduct an environmental fate and transport analysis of ethanol in air, surface water, and groundwater. The Office of Environmental Health Hazard Assessment shall prepare an analysis of the health risks of ethanol in gasoline, the products of incomplete combustion of ethanol in gasoline, and any resulting secondary transformation products. These reports are to be peer reviewed and presented to the Environmental Policy Council by December 31, 1999 for its consideration.

11. The California Energy Commission (CEC) shall evaluate by December 31, 1999 and report to the Governor and the Secretary for Environmental Protection the potential for development of a California waste-based or other biomass ethanol industry. CEC shall evaluate what steps, if any, would be appropriate to foster waste-based or other biomass ethanol development in California should ethanol be found to be an acceptable substitute for MTBE.

IN WITNESS WHEREOF I have hereunto set my hand and caused the Great Seal of the State of California to be affixed this 25th day of March 1999.

Governor of California

(*Signature of Gray Davis*)

ATTEST:

(Signature of Bill Jones)

Secretary of State

This document can also be found at: http://www.ca.gov/s/governor/d599.html

Appendix B

Glossary

Appendix B

Glossary

A

Accumulating shear: A feller-buncher shearhead that is capable of accumulating and holding 2 or more cut stems.

Acid hydrolysis: A chemical process in which acid is used to convert cellulose or starch to sugar.

Aerobic: Life or biological processes that can occur only in the presence of oxygen.

Agricultural residues: Above-ground organic matter left in the field after the harvest of a crop.

Alcohol: A general class of hydrocarbons that contain a hydroxyl group (OH). The term "alcohol" is often used interchangeably with the term "ethanol," even though there are many types of alcohol. (See, Ethanol, Methanol.)

Alkali: A soluble mineral salt.

Ambient air quality: The condition of the air in the surrounding environment.

Anaerobic: Life or biological processes that occur in the absence of oxygen.

Anaerobic digestion: A biochemical process by which organic matter is decomposed by bacteria in the absence of oxygen, producing methane and other byproducts.

Attainment area: A geographic region where the concentration of a specific air pollutant does not exceed federal standards.

Avoided costs: An investment guideline describing the value of a conservation or generation resource investment by the cost of more expensive resources that a utility would otherwise have to acquire.

B

Barrel of oil equivalent: A unit of energy equal to the amount of energy contained in a barrel of crude oil. Approximately 5.78 million Btu or 1,700 kWh. A barrel is a liquid measure equal to 42 gallons.

BDT: See bone dry ton

Bioaccumulants: Substances in contaminated air, water, or food that increase in concentration in living organisms exposed to them because the substances are very slowly metabolized or excreted.

Biochemical conversion process: The use of living organisms or their products to convert organic material to fuels.

Biochemical oxygen demand: (BOD) A standard means of estimating the degree of pollution of water supplies, especially those which receive contamination from sewage and industrial waste. BOD is the amount of oxygen needed by bacteria and other microorganisms to decompose organic matter in water. The greater the BOD, the greater the degree of pollution. Biochemical oxygen demand is a process that occurs over a period of time and is commonly measured for a five-day period, referred to as BOD5.

Biodegradable: Capable of decomposing rapidly under natural conditions.

Bioenergy: Useful, renewable energy produced from organic matter. The conversion of the complex carbohydrates in organic matter to energy. Organic matter may either be used directly as a fuel or processed into liquids and gases.

Biofuels: Fuels made from cellulosic biomass resources. Biofuels include ethanol, biodiesel, and methanol.

Biogas: A combustible gas derived from decomposing biological waste. Biogas normally consists of 50 to 60 percent methane.

Biomass: Organic matter available on a renewable basis. Biomass includes forest and mill residues, agricultural crops and wastes, wood and wood wastes, animal wastes, livestock operation residues, aquatic plants, fast-growing trees and plants, and municipal and industrial wastes.

Biomass fuel: Liquid, solid, or gaseous fuel produced by conversion of biomass.

Biomass energy: See Bioenergy.

Biotechnology: Technology that use living organisms to produce products such as medicines, to improve plants or animals, or to produce microorganisms for bioremediation.

BOD: See Biochemical oxygen demand.

Boiler: Any device used to burn biomass fuel to heat water for generating steam.

Bone dry ton: A ton of material (2000 lbs.) having zero percent moisture content. A residue heated in an oven at a constant temperature of 212 degrees F or above until its weight stabilizes is considered bone dry or oven dry.

British thermal unit: (Btu) A unit of heat energy equal to the heat needed to raise the temperature of one pound of water from 60ºF to 61ºF at one atmosphere pressure.

Btu: See British thermal unit

C

Capital cost: The total investment needed to complete a project and bring it to a commercially operable status. The cost of construction of a new plant. The expenditures for the purchase or acquisition of existing facilities.

Carbohydrate: A chemical compound made up of carbon, hydrogen, and oxygen. Includes sugars, cellulose, and starches.

Cellulose: The main carbohydrate in plants. Cellulose forms the skeletal structure of the plant cell wall.

Centralized sewage treatment: The collection and treatment of sewage from many sources to remove pollutants and pathogens.

Chipper: A machine that produces wood chips by knife action.

Chips: Woody material cut into short, thin wafers. Chips are used as a raw material for pulping and fiberboard or as biomass fuel.

Clean Air Act: Federal law enacted originally in 1970 establishing ambient air quality emission standards to be implemented by participating states. Latest amendment was in 1990.

Clearcut: The removal, in a single cutting, of the entire stand of trees within a designated area. Stand regeneration is accomplished by planting the site or by natural seeding from adjacent stands.

Cogeneration: The sequential production of electricity and useful thermal energy from a common fuel source. Reject heat from industrial processes can be used to power an electric generator (bottoming cycle). Conversely, surplus heat from an electric generating plant can be used for industrial processes, or space and water heating purposes (topping cycle).

Combined cycle: Two or more generation processes in series or in parallel, configured to optimize the energy output of the system.

Combustion: Combustion: Burning. The transformation of biomass fuel into heat, chemicals, and gases through chemical combination of hydrogen and carbon in the fuel with oxygen in the air.

Combustion gases: The gases released from a combustion process.

Commercial forest land: Forested land which is capable of producing new growth at a minimum rate of 20 cubic feet per acre/per year, excluding lands withdrawn from timber production by statute or administrative regulation.

Cull: Any item of production picked out for rejection because it does not meet certain specifications. Chip culls and utility culls are specifically defined for purposes of log grading by percentage of sound wood content.

D

Denature: The process of adding a substance to ethyl alcohol to make it unfit for human consumption.

Digester: An airtight vessel or enclosure in which bacteria decomposes biomass in water to produce biogas.

Discount rate: A rate used to convert future costs or benefits to their present value.

Discounting: A method of converting future dollars into present values, accounting for interest costs or forgone investment income. Used to convert a future payment into a value that is equivalent to a payment now.

Distillation: The process to separate the components of a liquid mixture by boiling the liquid and then recondensing the resulting vapor.

Distillers' dried grains: (DDGS) The dried byproduct of the grain fermentation process. Typically used as a high-protein animal feed.

Distribution: The transfer of electricity from the transmission network to the consumer.

Draft environmental impact statement: (DEIS) A draft statement of environmental effects. Section 102 of the National Environmental Policy Act requires a DEIS for all major federal actions. The DEIS is released to the public and other agencies for comment and review.

Duff: The layer of forest litter.

E

Effluent: The treated waste water discharged by sewage treatment plants.

Emission offset: A reduction in the air pollution emissions of existing sources to compensate for emissions from new sources.

Emissions: Waste substances released into the air or water.

Endangered species: See Threatened, endangered, and sensitive species.

Energy: The ability to do work.

Energy crops: Crops grown specifically for their fuel value. These include food crops such as corn and sugarcane, and nonfood crops such as poplar trees and switchgrass. Currently, two energy crops are under development: short-rotation woody crops, which are fast-growing hardwood trees harvested in 5 to 8 years, and herbaceous energy crops, such as perennial grasses, which are harvested annually after taking 2 to 3 years to reach full productivity.

Environment: The external conditions that affect organisms and influence their development and survival.

Environmental assessment: (EA) A public document that analyzes a proposed federal action for the possibility of significant environmental impacts. The analysis is required by NEPA. If the environmental impacts will be significant, the federal agency must then prepare an environmental impact statement.

Environmental impact statement: (EIS; FEIS) A statement of the environmental effects of a proposed action and of alternative actions. Section 102 of the National Environmental Policy Act (NEPA) requires an EIS for all major federal actions.

Enzymatic hydrolysis: A process by which enzymes (biological catalysts) are used to break down starch or cellulose into sugar.

Ethanol: Ethyl alcohol produced by fermentation and distillation. An alcohol compound with the chemical formula CH3CH20H formed during sugar fermentation by yeast. Grain alcohol.

Excess annual growth: The amount by which new forest growth exceeds removal in a year. The annual quantity of wood produced in a forest in excess of market demand.

Externality: A cost or benefit not accounted for in the price of goods or services. Often "externality" refers to the cost of pollution and other environmental impacts.

F

Feedstock: Any material which is converted to another form or product.

Fell: To cut down a tree. Cutting down trees and sawing them to manageable lengths is referred to as "felling and bucking" or "falling and bucking."

Feller-buncher: A self-propelled machine that cuts trees with giant shears near ground level and then stacks the trees into piles to await skidding.

Fermentation: The biological conversion of biomass by yeast or sugar. The products of fermentation are carbon dioxide and alcohol.

Forest Plan: The document that sets goals, objectives, desired future condition, standards and guidelines, and overall programmatic direction for a National Forest.
Required by the National Forest Management Act of 1976.

Forest residues: Material not harvested or removed from logging sites in commercial hardwood and softwood stands as well as material resulting from forest management operations such as pre-commercial thinnings and removal of dead and dying trees.

Forest health: A condition of ecosystem sustainability and attainment of management objectives for a given forest area. Usually considered to include green trees, snags, resilient stands growing at a moderate rate, and endemic levels of insects and disease. Natural processes still function or are duplicated through management intervention.

Forested areas or land: Any land that is capable of producing or has produced forest growth or, if lacking forest growth, has evidence of a former forest and is not now in other use.

Fossil fuel: Solid, liquid, or gaseous fuels formed in the ground after millions of years by chemical and physical changes in plant and animal residues under high temperature and pressure. Oil, natural gas, and coal are fossil fuels.

Fuel: Any material that can be converted to energy.

Fuel cycle: The series of steps required to produce electricity. The fuel cycle includes mining or otherwise acquiring the raw fuel source, processing and cleaning the fuel, transport, electricity generation, waste management and plant decommissioning.

Fuel handling system: A system for unloading wood fuel from vans or trucks, transporting the fuel to a storage pile or bin, and conveying the fuel from storage to the boiler or other energy conversion equipment.

Furnace: An enclosed chamber or container used to burn biomass in a controlled manner to produce heat for space or process heating.

G

Gasification: A chemical or heat process to convert a solid fuel to a gaseous form.

Gasifier: A device for converting solid fuel into gaseous fuel. In biomass systems, the process is referred to as pyrolitic distillation. See Pyrolysis.

Gasohol: A motor vehicle fuel which is a blend of 90 percent (by volume) unleaded gasoline with 10 percent ethanol.

Generator: A machine used for converting rotating mechanical energy to electrical energy.

Global Climate Change: Also referred to as greenhouse effect: The effect of certain gases in the Earth's atmosphere in trapping heat from the sun.

Green ton: 2,000 pounds of undried biomass material. Moisture content must be specified if green tons are used as a measure of fuel energy.

Greenhouse gases: Gases that trap the heat of the sun in the Earth's atmosphere, producing the greenhouse effect. The two major greenhouse gases are water vapor and carbon dioxide. Other greenhouse gases include methane, ozone, chlorofluorocarbons, and nitrous oxide.

Grid: An electric utility's system for distributing power.

H

Habitat: The area where a plant or animal lives and grows under natural conditions. Habitat includes living and non-living attributes and provides all requirements for food and shelter.

Hammermill: A device consisting of a rotating head with free-swinging hammers which reduce chips or hogged fuel to a predetermined particle size through a perforated screen.

Hardwoods: Usually broad-leaved and deciduous trees.

Hemicellulose:

Horsepower: (electrical horsepower; hp) A unit for measuring the rate of mechanical energy output. The term is usually applied to engines or electric motors to describe maximum output. 1 hp = 745.7 Watts = 0.746 kW = 2,545 Btu/hr.

Hurdle Rate: See Stefan

Hydrocarbon: Any chemical compound containing hydrogen, oxygen, and carbon.

Hydrolysis: Decomposition of a chemical compound by reaction with water.

I

Incinerator: Any device used to burn solid or liquid residues or wastes as a method of disposal. In some incinerators, provisions are made for recovering the heat produced.

Inorganic compounds: Those compounds lacking carbon but including carbonates and cyanides. Compounds not having the organized anatomical structure of animal or vegetable life.

Investment tax credit: A specified percentage of the dollar amount of certain new investments that a company can deduct as a credit against its income tax bill.

K

Kilowatt: (kW) A measure of electrical power equal to 1,000 Watts. 1 kW = 3,413 Btu/hr = 1.341 horsepower.

Kilowatt hour: (kWh) A measure of energy equivalent to the expenditure of one kilowatt for one hour. For example, 1 kWh will light a 100-watt light bulb for 10 hours. 1 kWh = 3,413 Btu.

L

Landfill gas: Gas that is generated by decomposition of organic material at landfill disposal sites. Landfill gas is approximately 50 percent methane.

Lignin: An amorphous polymer related to cellulose that together with cellulose forms the cell walls of woody plants and acts as the bonding agent between cells.

Log choker: A length of cable or chain that is wrapped around a log or harvested tree to secure the log to the winch cable of a skidder or to an overhead cable yarding line.

Logging residues: The unused portion of wood and bark left on the ground after harvesting merchantable wood. The material may include tops, broken pieces, and unmerchantable species.

M

Materials recovery facility: A recycling facility for municipal solid waste.

Merchantable: Logs from which at least of the volume can be converted into sound grades of lumber ("standard and better" framing lumber).

Methane: An odorless, colorless, flammable gas with the formula CH4 that is the primary constituent of natural gas.

Methanol: Methyl alcohol having the chemical formula CH30H. Methanol is usually produced by chemical conversion at high temperatures and pressures. Wood alcohol. Although usually produced from natural gas, methanol can be produced from gasified biomass (syngas).

Metric ton: (or tonne) 1000 kilograms. 1 metric ton = 2,204.62 lb = 1.023 short tons.

MGD: Million gallons per day.

Mill residue: Wood and bark residues produced in processing logs into lumber, plywood, and paper.

Mitigation: Steps taken to avoid or minimize negative environmental impacts. Mitigation can include: avoiding the impact by not taking a certain action; minimizing impacts by limiting the degree or magnitude of the action; rectifying the impact by repairing or restoring the affected environment; reducing the impact by protective steps required with the action; and compensating for the impact by replacing or providing substitute resources.

Moisture Content: (MC) The weight of the water contained in wood, usually expressed as a percentage of weight, either oven-dry or as received.

MRF: See Materials recovery facility.

MSW: See Municipal solid waste.

Municipal solid waste: (MSW) Garbage. Refuse offering the potential for energy recovery; includes residential, commercial, and institutional wastes.

N

National Environmental Policy Act: (NEPA) A federal law enacted in 1969 that requires all federal agencies to consider and analyze the environmental impacts of any proposed action. NEPA requires an environmental impact statement for major federal actions significantly affecting the quality of the environment. NEPA requires federal agencies to inform and involve the public in the agency's decision making process and to consider the environmental impacts of the agency's decision.

National Forest Management Act: A federal law passed in 1976 as an amendment to the Forest and Rangeland Renewable Resources Planning Act requiring the preparation of Regional Guides and Forest Plans and the preparation of regulations to guide that development.

NEPA: See National Environmental Policy Act

Net heating value: (NHV) The potential energy available in the fuel as received, taking into account the energy loss in evaporating and superheating the water in the sample. Expressed as NVH = (HHV x (1- MC / 100) - (LH(2)O x MC / 100)

Net present value: The sum of the costs and benefits of a project or activity. Future benefits and costs are discounted to account for interest costs.

O

Old growth: Timber stands with the following characteristics: large mature and over-mature trees in the overstory, snags, dead and decaying logs on the ground, and a multi-layered canopy with trees of several age classes.

Organic: Derived from living organisms.

Organic compounds: Chemical compounds based on carbon chains or rings and also containing hydrogen, with or without oxygen, nitrogen, and other elements.

Oven dry ton: (ODT) Also called bone dry ton: an amount of wood that weighs 2,000 pounds at zero percent moisture content.

P

Partial cut: A harvest method in which portions of a stand of timber are cut during a number of entries over time. Precommercial thinning operations are not considered partial cuts.

Particulate: A small, discrete mass of solid or liquid matter that remains individually dispersed in gas or liquid emissions. Particulates take the form of aerosol, dust, fume, mist, smoke, or spray. Each of these forms has different properties.

Particulate emissions: Fine liquid or solid particles discharged with exhaust gases. Usually measured as grains per cubic foot or pounds per million Btu input.

pH: A measure of acidity or alkalinity. A pH of 7 represents neutrality. Acid substances have lower pH. Basic substances have higher pH.

Pilot scale: The size of a system between the small laboratory model size (bench scale) and a full-size system.

Pound: Pound mass (sometimes abbreviated lb(m)). A unit of mass equal to 0.454 kilograms.

Precommercial thinning: Thinning for timber stand improvement purposes, generally in young, densely stocked stands.

Prescription: Specific written directions for forest management activities.

Present value: The worth of future receipts or costs expressed in current value. To obtain present value, an interest rate is used to discount future receipts or costs.

Process heat: Heat used in an industrial process rather than for space heating or other housekeeping purposes.

Pyrolysis: The thermal decomposition of biomass at high temperatures (greater than 400ø F, or 200ø C) in the absence of air. The end product of pyrolysis is a mixture of solids (char), liquids (oxygenated oils), and gases (methane, carbon monoxide, and carbon dioxide) with proportions determined by operating temperature, pressure, oxygen content, and other conditions.

R

RDF: See Refuse-derived fuel.

Recovery boiler: A pulp mill boiler in which lignin and spent cooking liquor (black liquor) is burned to generate steam.

Refuse-derived fuel: (RDF) Fuel prepared from municipal solid waste. Noncombustible materials such as rocks, glass, and metals are removed, and the remaining combustible portion of the solid waste is chopped or shredded. RDF facilities process between 100 and 3000 tons of MSW per day.

Renewable energy resource: An energy resource replenished continuously or that is replaced after use through natural means. Sustainable energy. Renewable energy resources include bioenergy, solar energy, wind energy, geothermal power, and hydropower.

Return on investment: (ROI) The interest rate at which the net present value of a project is zero. Multiple values are possible.

ROI: See Return on investment.

Rotation: The number of years allotted to establish and grow a forest stand to maturity.

S

Sewage: The waste water from domestic, commercial and industrial sources carried by sewers.

Short rotation energy plantation: Plantings established and managed under short-rotation intensive culture practices.

Short rotation intensive culture: Intensive management and harvesting at 2 to 10 year intervals of cycles of specially selected fast- growing hardwood species for the purpose of producing wood as an energy feedstock.

Silviculture: The theory and practice of forest stand establishment and management.

Skidder: A self-propelled machine to transport harvested trees or logs from the stump area to the landing or work deck.

Slash: The unmerchantable material left on site subsequent to harvesting a timber stand, including tops, limbs, cull sections.

Slow pyrolysis: Thermal conversion of biomass to fuel by slow heating to less than 450øC in the absence of oxygen.

Sludge: The mixture of organic and inorganic substances separated from sewage.

Stand: (tree stand, timber stand) A community of trees managed as a unit. Trees or other vegetation occupying a specific area, sufficiently uniform in species composition, age arrangement, and condition as to be distinguishable from the forest or other cover on adjoining areas.

Stillage: The grains and liquid effluent remaining after distillation.

Stoichiometric condition: That condition at which the proportion of the air-to-fuel is such that all combustible products will be completely burned with no oxygen remaining in the combustion air.

Sunk cost: A cost already incurred and therefore not considered in making a current investment decision.

Surplus electricity: Electricity produced by cogeneration equipment in excess of the needs of an associated factory or business.

Sustainable: An ecosystem condition in which biodiversity, renewability, and resource productivity are maintained over time.

Sustained yield: The maintenance in perpetuity of regular, periodic harvest of wood resources from forest land without damaging the productivity of the land.

T

Therm: A unit of energy equal to 100,000 Btus; used primarily for natural gas.

Timberland: Forest land capable of producing 20 cubic feet of wood per acre per year.

Tipping fee: A fee for disposal of waste.

Toxic substances: A chemical or mixture of chemicals that presents a high risk of injury to human health or to the environment.

Transmission: The process of long-distance transport of electrical energy, generally accomplished by raising the electric current to high voltages.

V

VOC: see Volatile organic compounds.

Volatile organic compounds: (VOC) Emissions of non-methane hydrocarbons, measured by standard DEQ methods.

Volatiles: Substances that are readily vaporized.

W

Waste streams: Unused solid or liquid by- products of a process.

Watershed: The drainage basin contributing water, organic matter, dissolved nutrients, and sediments to a stream or lake.

Watt: The common base unit of power in the metric system. One watt equals one joule per second, or the power developed in a circuit by a current of one ampere flowing through a potential difference of one volt. One Watt = 3.413 Btu/hr.

Wetlands: Lands where saturation with water is the primary factor determining soil development and the kinds of plant and animal communities living on or under the surface.

Whole-tree harvesting: A harvesting method in which the whole tree (above the stump) is removed.

Y

Yarding: The initial movement of logs from the point of felling to a central loading area or landing.

References:

The Bioenergy Glossary, published by the Oregon Department of Energy

Washington State Biomass Data Book, J. A. Deshaye, J. D. Kerstetter, Washington State Energy Office, Olympia, WA 98504-3165. July 1991

Appendix C

Chapter III

Waste Biomass Resources in California

Appendix C

Chapter III
Waste Biomass Resources in California

What are the components of cellulosic biomass?
About 35% to 50% of the material are cellulose, a polymer of the six-carbon sugar glucose that forms a crystalline structure. Another 15% to 30% are hemicellulose, a heterogeneous polymer of various sugars generally dominated by the five-carbon sugar xylose. The remaining 20% to 30% are composed primarily of lignin (a heterogeneous aromatic polymer), with lesser amounts of extractives, ash and other components.

How much forest land in California should be thinned?
According to the Department of Forestry and Fire Protection, California's timber industry yields about $1 billion annually. The state has approximately 40 million acres of forestland, most being in the northern portion of the state. There are approximately 16 million acres of commercial timberland in California. Of this, approximately 13 million acres are at a slope of 30° or less, a requirement for thinning the forest economically.

California's Agricultural Crops

Field and Seed Crops

Crop	97 Prod. Acres Harv.	Conv. Factor	Million BDT	92 CEC Biom Rprt
Barley	180,000	1.3	234,000	305,500
Bean	132,000	1.0	132,000	161,500
Corn	575,000	4.7	2,702,500	1,565,500
Cotton	1,059,000	1.5	1,588,500	1,503,000
Oat	35,000	1.2	42,000	39,500
Rice	510,000	3.5	1,785,000	1,309,600
Sugar Beets	99,000	2.4	237,600	406,800
Wheat	544,000	1.9	1,033,600	1,189,900
Other	?	(1.4)?	140,000	137,400
TOTAL	3,134,000		**7,895,200**	*6,618,700*

Source: California Department of Food and Agriculture, *1998 California Agricultural Resource Directory*, November 1998

Conversion factors: California Energy Commission*,1991 Biomass Resource Assessment Report for California*, *Draft;* P500-94-007, December 1992

Fruit and Nut Crop

Crop	97 Acres Harv	Conv. Factor	MBDT	92 CEC Biom Rprt
almond	410,000	1.3	533,000	350,200
apple	38,500	2.2	84,700	35,900
apricot	19,100	2.0	38,200	25,000
avocado	57,700	1.5	86,550	73,000
cherry	13,700	0.4	5,480	2,700
date	4,800	1.0	4,800	3,200
fig	16,000	2.2	35,200	21,000
grapefruit	18,600	1.0	18,600	12,200
grape	675,700	2.0	1,351,400	873,000
kiwi	6,100	2.0	12,200	
lemon	46,500	1.0	46,500	29,400
lime	-	1.0	-	600
olive	35,300	1.5	52,950	29,200
orange	199,000	1.0	199,000	111,100
peach	66,200	2.0	132,400	73,500
pear	22,800	2.3	51,300	32,800
pistachio	65,400	1	65,400	
plum	42,000	1.5	63,000	39,800
prune	79,500	1.0	79,500	50,200
walnut	177,200	1.0	177,200	118,200
TOTAL			**3,037,380**	**1,881,000**

Source: California Department of Food and Agriculture, *1998 California Agricultural Resource Directory*, November 1998

Conversion factors: California Energy Commission*,1991 Biomass Resource Assessment Report for California*, *Draft;* P500-94-007, December 1992

Vegetable Crops

Crop	97 harv acre	Conv. Factor	Mbdt	92 CEC Biom Rprt
artichoke	9,100	1.7	15,470	19,400
asparagus	30,100	2.2	66,220	75,300
cucumber	5,700	1.7	9,690	10,300
lettuce	201,000	1.0	201,000	209,200
melon	107,000	1.2	128,400	147,800
potato	43,700	1.2	52,440	58,800
squash		1.2		9,500
tomato	300,800	1.3	391,040	388,800
TOTAL	*697,400*		*864,260*	*919,100*

Source: California Department of Food and Agriculture, *1998 California Agricultural Resource Directory*, November 1998

Conversion factors: California Energy Commission*,1991 Biomass Resource Assessment Report for California*, *Draft;* P500-94-007, December 1992

Appendix D

Chapter V

Biomass Conversion Options

APPENDIX D

Chapter 5
Biomass Conversion Options

There is real potential for biobased products to be cost-competitive with petroleum-based production if research, development, and demonstrations reduce processing costs. (Ref. D-1) Advances in chemical **pretreatment** of cellulosic wastes and in **biological conversion** of the resulting molecules (such as sugars) make major cost reductions seem likely. This Appendix describes the most competitive current technologies and probable directions for increasing the rate of conversion, yield and efficiency, and thereby lowering the costs of production, of ethanol, electricity, and chemical co-products from urban, agricultural, and forest wastes.

After the feedstocks are delivered to the plant, they are reduced in size, if necessary, by cutting and milling, and may be washed. Most biomass conversion processes then utilize two or three technologies, sometimes in combination:

(1) pretreatment that makes the cellulosic components of the biomass more accessible to
(2) hydrolysis by acids, or by enzymes called "cellulases", that shorten sugar polymers into sugars that then undergo
(3) fermentation by microbes , converting the five- and six-carbon sugars to ethanol and other oxygenated chemicals.

The latter two steps may be combined into Simultaneous Saccharification and Fermentation, called SSF. (Ref. D-2) If cellulases are produced in the same vessel, the approach is called consolidated bioprocessing (Ref. D-3) or DMC (Direct Microbial Conversion.) After fermentation is complete, the ethanol produced can be distilled to the characteristics required for its uses, such as transportation fuel.

The remainder of this chapter surveys the various technologies for converting biomass to ethanol, electricity, and added-value co-products.

D-1 Pretreatment, Hydrolysis, and Fermentation

The methods referred to as pretreatment separate the four chemical components of biomass (hemicelluloses, cellulose, lignin, and extractives) to various extents, and make them accessible to further chemical or biological treatment. It is preferable to make the pretreatment as mild as possible, so as not to diminish the chemical values in the biomass.

The term hydrolysis means decomposition or dissolving in a watery medium. In the context of biorefining, it generally means cutting the long hemicellulose and cellulose molecules, which are polymers, chemically into their component sugars. These sugars are much shorter molecules, each containing only five or six carbon atoms, plus hydrogen and oxygen. These are called pentoses and hexoses, respectively, and they can be converted into ethanol.

The conversion of starches and sugars to ethanol is called fermentation, a process that has been practiced by mankind as long as the cultivation of grain and grapes.

D 1.1 Pretreatment

Conversion of biomass to ethanol, electricity and co-products usually requires a mechanical size reduction step, followed by physical, chemical, or biological pretreatment, or sometimes a combination of these (Ref. D-4) Commercial wood chips have 1-3 cm length, width, and 0.5-1 cm thickness, that is usually reduced to 0.3 cm or less in every dimension before further processing.

The most common physical pretreatments are (1) comminution, that is, size reduction by ball milling or compression milling, and (2) aqueous/steam processing, to be discussed below.

Chemical pretreatments to make the biomass more digestible have received by far the most research interest. They include dilute acid, alkaline, organic solvent, ammonia, sulfur dioxide, carbon dioxide, or other chemicals.

Biological pretreatments have been tested primarily to solubilize lignin, and so make the cellulose more accessible to hydrolysis and fermentation. Sometimes a combination of chemical and biological methods has been employed.

These various pretreatment processes result in a variety of product streams for further processing. In many cases, the cellulose, hemicellulose, and lignin are separated into two streams, such as a liquid stream rich in hemicellulose, and a stream containing the cellulose and lignin as solids; or, if delignification is used, the liquid stream contains the lignin and hemis, and the second stream contains cellulose and the remaining unsolubilized hemis as solids. Combined pretreatments may result in separating the three major components and extractives into individual product streams.

Three examples of the wide variety of possible pretreatments are the organosolv, AFEX, and aqueous/steam methods.

A variation on the dilute acid processes known as ACOS or organosolv, adds acetone to a dilute acid solution with the objective of producing higher yields of sugar (in particular, glucose), leading to higher yields of ethanol after fermentation.

A line of development pursued by Texas A&M uses dilute ammonia, an alkaline chemical, to aid hydrolysis. A sudden pressure release (colloquially called an "explosion") is employed in this AFEX method. Advantages claimed for the method are reduced degradation of the materials to be fermented to ethanol, and no economic need to recycle the ammonia.

Aqueous/steam pretreatment methods avoid or minimize the use of acids and other chemical reagents, by processing biomass with hot water and/or steam at high temperatures and pressures for short periods of time. Their goals include reduction of milling costs, high sugar recovery, and minimal inhibition of fermentation. One subclass of these methods, sometimes called aquasolv, uses liquid hot water pretreatment. Another mixes steam with biomass, such as wood chips, in a pressure cooker for a few minutes at temperatures near 200∞C, then releases the mixture to atmospheric pressure in a "steam explosion". This technology has been advanced at the University of British Columbia, among others, and embodied in a continuous process by a Canadian company, Staketech. Both aqueous/steam and dilute acid methods are being considered as treatments to precede enzymatic hydrolysis.

If an appreciable fraction of the delivered biomass is in the form of easily-removable extractives, as in California softwoods, it is often best to remove these first, for conversion into valuable chemical products, and to ease further processing of the three major components. Thus, we now discuss separation of extractives as a form of pretreatment.

Separation of Extractives

The bark and needles of California softwoods contain resins and other valuable biochemicals that are part of the immune system of the trees. (The taxol from yew trees in the Pacific Northwest and maltol derived from Canadian conifers are two examples.) There is amorphous silica in rice straw and hulls that may be adapted to the demands of rubber and other industries. Organic *and* inorganic substances (ash) that are smaller but valuable fractions of biomass will here be called extractives. Separating these extractives in an early pretreatment step (for subsequent conversion to pharmaceutical or other commercial products) serves two valuable purposes: the manufacture of co-products to make the biorefinery economically self-sustaining, and the removal of materials that might inhibit later steps in the processing of hemicelluloses, cellulose and lignin.

The percentage in extractives (typically 4% to 5%) varies with biomass species and is highest in small trees and in residues rich in bark and branches, where up to 20% of the raw material (dry basis) is extractives. Recovery of extractives from coniferous trees was the foundation of the naval stores industry. A newly important and growing sector is directed toward natural chemicals from biomass used in food flavorings, fragrances, and as pharmaceutical intermediates. The sources of this biomass may include degraded trees as well as small living trees and shrubs that need to be removed to maintain a healthy and fire-safe forest.

Because organic extractives are soluble in simple alcohols and in hot pressurized water, they can be separated by mild front-end pretreatment. The process steps may include water treatment of the feedstocks to saturate the fiber materials through complete capillary penetration, ethanol extraction to remove slightly hydrophobic materials, followed by an ethyl acetate extraction, if needed. Inorganic material is removed in all steps, preferentially the first one. The resulting solid product, separated from the extractive streams, is a “refined biomass” suitable for conversion into ethanol, pulp, other commodity products, or power.

D 1.2 Hydrolysis

Several of the following subsections on hydrolysis and fermentation utilize historical and current information provided by the National Renewable Energy Laboratory (NREL) in its 1999 Bioethanol Strategic Roadmap (Ref. D-2). Projections of future performance consider this and other technical material published by NREL, but also include numerous other judgments from the technical literature, collected from academic, governmental, and industrial sources. The hydrolysis methods of this section are presented in an order generally ranging from those that rely most on chemical engineering to those more dependent on new biological (especially, genetic) technologies.

Concentrated Acid Hydrolysis

Dissolving and hydrolyzing cellulose with concentrated sulfuric acid followed by dilution with water at modest temperatures, provides complete and rapid conversion to glucose, with little degradation. Most of the research on this approach after 1918 has been performed on agricultural residues. In 1937 the Germans built commercial-scale plants based on the use and recovery of hydrochloric acid. Work at the United States Department of Agriculture laboratory in Peoria, Illinois further refined the concentrated sulfuric acid process. The Japanese then introduced membranes to separate the sugar from the acid in the product stream. Further improvements were made in the United States by Purdue University and by the Tennessee Valley Authority (TVA). Minimizing the use of sulfuric acid and recycling it effectively are critical factors in the economic viability of the process.

Concentrated acid methods will be used by Arkenol in its rice-straw-to-ethanol plant at Rio Linda in Sacramento County, California and by the Masada Resource Group in its MSW-to-ethanol facility in Orange County, New York. Arkenol also plans to recover amorphous silica from the rice straws as a co-product.

Dilute Acid Hydrolysis

Dilute acid hydrolysis is the oldest technology for converting biomass to ethanol. Begun in Germany in 1898, the process was developed further there and in the United States by the USDA's Forest Products Laboratory and at TVA facilities. A dilute solution of sulfuric acid (H_2SO_4) percolating through a bed of wood chips was found by 1952 to be a simple and effective reactor design. Petroleum shortages of the 1970s renewed interest in this technology under USDA and DOE sponsorship. By 1985 the limits of the percolation designs were recognized: their 70% glucose yields were achieved by producing highly dilute sugar streams. Attention shifted to higher solids concentrations, countercurrent flow, and shorter processing times (6 to 10 seconds) at higher temperatures (around 240 'C.) Most current designs use two stages of hydrolysis, the first at milder conditions to maximize the yield from hemicellulose, while conditions in the second stage are optimized for the cellulose fraction. This is diagrammed in Figure D-1 (from Ref. D-2). Both of these hydrolyzed solutions are then fermented to alcohol. Lime used to neutralize residual acids before the fermentation stage is converted to gypsum for sale as a soil amendment, or for disposal. Residual cellulose and lignin are used as boiler fuel for electricity or steam production.

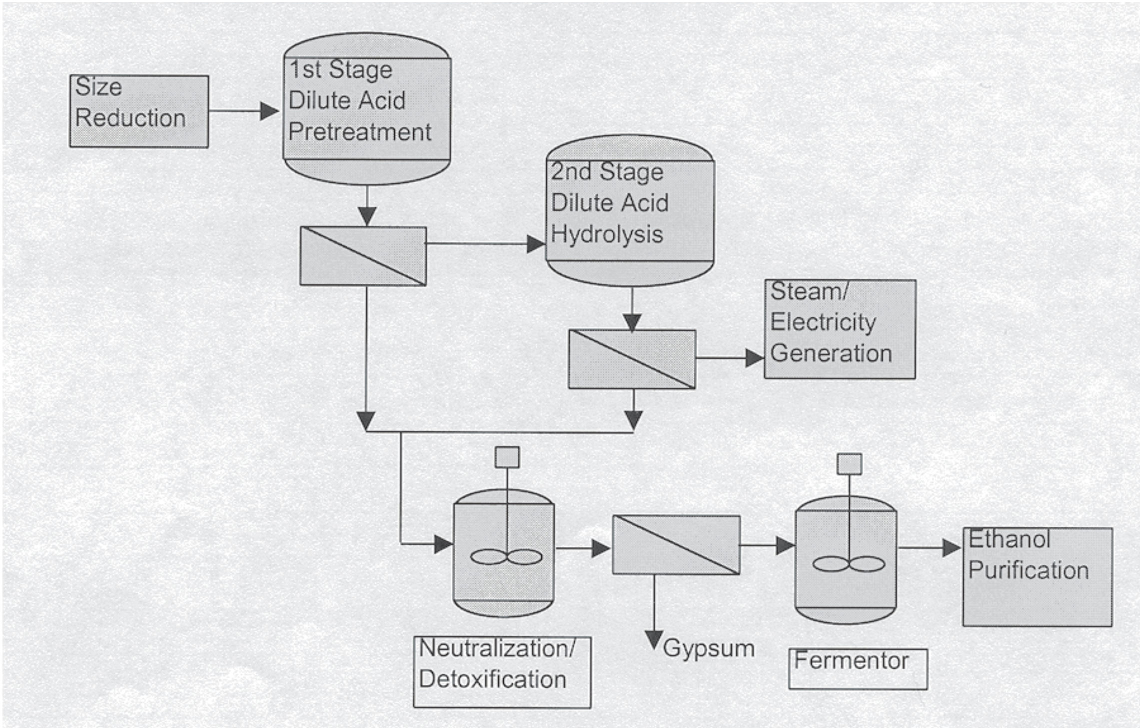


Figure D-1: General Schematic of Two-Stage Dilute Acid Hydrolysis Process (from Ref. D-2)

BC International (BCI) and the DOE Office of Fuel Development have formed a cost-shared partnership to develop a 20 million gallons per year biomass-to-ethanol plant in Jennings, LA. Dilute acid hydrolysis will be used to recover sugar from bagasse (sugar cane wastes) and rice hulls, and a proprietary, genetically-engineered organism will ferment the sugars from bagasse and rice hulls to ethanol.

BCI presently plans to use two-stage dilute sulfuric acid technology with rice straw and wood wastes as the feedstocks in the Gridley biomass-to-ethanol facility collocated with the Pacific Oroville Power Plant. If enzymatic hydrolysis (to be discussed) proves soon to be reliable and cost-effective, then one-stage of dilute acid pretreatment followed by enzymatic hydrolysis will be considered as an alternative.

The Collins Pine/BCI project in Chester, CA, is also collocated with an electric power plant. The plan is to pretreat the softwood feedstocks with dilute sulfuric acid, followed by enzymatic hydrolysis and fermentation of sugars to ethanol (using proprietary bacterial enzymes). The softwood extractives will be converted to two or three chemical co-products: the beginnings of a California forest waste biorefinery.

Tembec and Georgia Pacific operate sulfite pulp mills that use dilute acid hydrolysis to dissolve hemicellulose and lignin from wood and produce specialty cellulose pulp. The hexose sugars in the spent sulfite stream are fermented to ethanol. The lignin is either burned to produce process steam or converted to value-added products such as dispersing agents or animal feed binders.

A dilute acid hydrolysis process using nitric acid, rather than sulfuric acid, was developed at the University of California and licensed to HFTA of Oakland, CA. Its stated economic advantages include being less corrosive to steel (permitting lower capital costs), no gypsum produced for landfill, and less use of acids and neutralizing chemicals. The Northeastern California Ethanol Manufacturing Feasibility Study (Ref D-5) prepared by the Quincy Library Group and other organizations evaluated nitric acid hydrolysis comparably with processes using dilute and concentrated sulfuric acids.

D 1.3 Hydrolysis Combined with Fermentation

In the fermentation step, sugars are converted by yeast into ethanol. This production step may follow hydrolysis or it may be combined with enzymatic hydrolysis.

Two widely-held convictions among many informed workers on biomass-to-ethanol conversion are: (1) that biological processes offer more promise than chemical processes for effecting large changes in the economics of production; and (2) that the integration of two or more steps (or consolidation of all steps) will result in increased efficiency of conversion and large cost savings.

The following paragraphs provide a simplified introduction to two developments that can qualitatively and quantitatively change the economic competition between biomass-derived and petroleum-derived fuels. The first is enzymatic hydrolysis. The second is direct microbial conversion. Both will be discussed below.

Interest in enzymatic hydrolysis of cellulose began in the South Pacific during World War II, when an organism now called *Trichoderma reesei* destroyed cotton clothing and tents. The U.S. Army laboratory at Natick, Massachusetts set out to understand the action of this fungus and to harness it. It found that the fungus produces enzymes that hydrolyze cellulose. The enzymes are protein chemicals that consist of a chain of amino acids. They are known as “cellulases” because of their effectiveness in hydrolyzing cellulose. Subsequent generations of cellulases have been developed with significantly increased effectiveness that has found commercial applications.

The first application of enzymes to the hydrolysis of wood for ethanol production was simply to replace the acid hydrolysis step with an enzymatic hydrolysis step. This process configuration is now known as Separate Hydrolysis and Fermentation, SHF. Pretreatment of the biomass, as discussed above, is performed to make the cellulose more accessible to the enzymes.

Subsequently an important process improvement was made by Gulf Oil Company and the University of Arkansas known as Simultaneous Saccharification (sugar-making) and Fermentation, SSF. This process configuration reduces the number of reactors by using one vessel for both hydrolysis and fermentation, which minimizes or avoids the problem of product inhibition associated with sugar buildup. In the SSF approach, cellulase enzymes and fermenting microbes are combined. As sugars are produced by the enzymes, the fermenting organisms convert them to ethanol.

More recently, the SSF process has been improved to include the cofermentation of both five-carbon and six-carbon sugars. This new variant of SSF, sometimes known as SSCF for Simultaneous Saccharification and CoFermentation, is shown schematically in Figure D-2. Note that SSCF combines hydrolysis (of hemicellulose and cellulose to sugars) and fermentation (of all sugars to ethanol) in one vessel, reducing capital costs, and by fermenting the sugars as soon as they form, eliminating problems associated with sugar accumulation and enzyme inhibition.

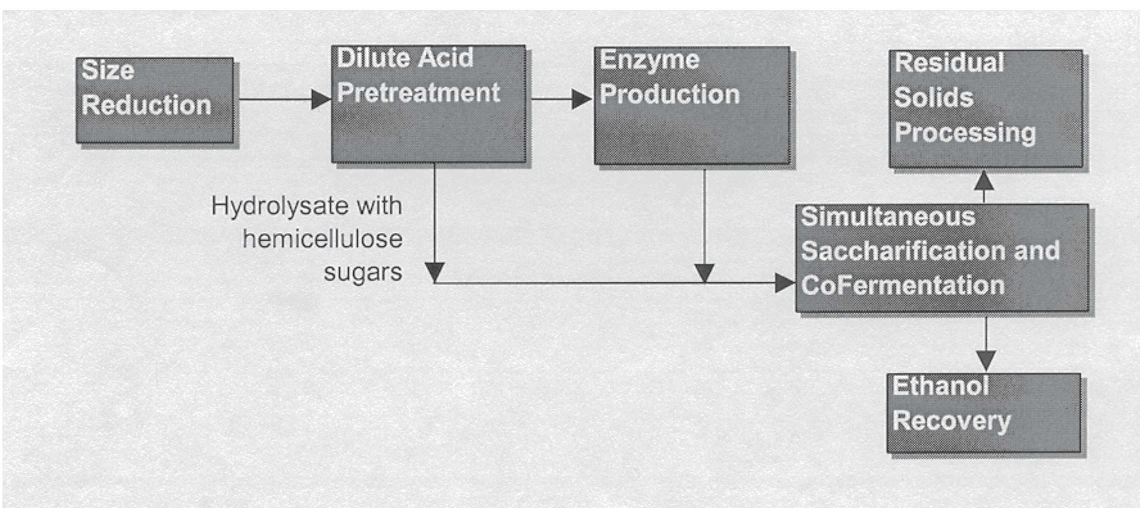


Figure D-2: The Enzyme Process Configured for Simultaneous Saccharification and CoFermentation (SSCF) (from Ref. D-2)

There are many feedstock options for enzymatic hydrolysis, including agricultural residues, paper wastes, wood wastes, green wastes. industrial process wastes, and energy crops. Feedstocks must first be milled to reduce the particle size of the biomass to allow more complete access to its porous structure. The biomass is then pretreated by dilute sulfuric acid or another economically viable method to hydrolyze the hemicellulose into sugars and make the cellulose available for hydrolysis. The pretreated material is then inoculated with an enzyme and fermenting agent such as a recombinant yeast, to hydrolyze the cellulose to sugar under mild temperature and pressure conditions, and to ferment all the sugars to ethanol. The remaining solids, mostly lignin, are separated out, dried and used as fuel for power, or possibly for co-products. The ethanol is distilled to the concentration and purity required for its use as a transportation fuel.

In 1997 Petro-Canada signed an agreement with Iogen Corporation to co-fund development of a biomass-to-ethanol technology based on Iogen's proprietary cellulase technology, and with the aid of the Canadian government, to begin construction of a demonstration plant in 1999. As previously mentioned, BC International intends to begin operation of their plant in Jennings, LA using dilute acid hydrolysis technology, but they will allow for the utilization of enzymatic hydrolysis when cellulase production becomes cost-effective.

Thus, two-stage dilute acid pretreatment and hydrolysis is a process available for near-term plant construction and operation. Single-stage dilute acid pretreatment followed by enzymatic hydrolysis (SHF) may be a near-term option or, more likely, a mid-term plant adaptation, if the price of producing cellulases with the required activities is significantly reduced. SSCF is not likely as a near-term option, but it may well qualify as an mid-term method according to the definitions used in this report. SSCF is widely perceived as one of the most attractive development routes, but because a mixture (sometimes called a cocktail, or a consortium) of enzymes with the proper balance of activities is required, the development time to attain this balance of enzymatic activities at attractive production costs is uncertain.

Two observations are helpful in establishing a context for microbial conversions. The first observation, from NREL (Ref. D-2) says, "While our understanding of cellulase's modes of action has improved, we have much more to learn before we can efficiently develop enzyme cocktails with increased activity." The second, from Lynd, Elander, and Wyman (Ref. D-3) says, "few experts would doubt the achievability of creating organisms compatible with consolidated processing given a sufficient effort," leaving open the question of what is a sufficient effort.

Direct Microbial Conversion (DMC)

When cellulase production (for the enzymatic hydrolysis of biomass feedstocks) and ethanol production are accomplished in a unit operation by a single microbial community, the process is called Direct Microbial Conversion (DMC). After mild pretreatment, the production of cellulase, hydrolysis of cellulose, and fermentation of all sugars are to be completed in one process step, called "consolidated bioprocessing". This requires that the genetic engineering methods used to enable enzymatic hydrolysis be extended to grow robust organisms capable of performing a variety of functions at the same temperature, pressure, and pH conditions in a single vessel.

Direct microbial conversion saves on capital and operating costs by reducing the number of vessels and by obtaining enzymes from the fermenter organisms. Using fermenters that produce cellulase eliminates the need to divert a portion of the sugar stream for cellulase production, thereby increasing overall ethanol yield. Also, DMC methods can be used to produce a wide variety of value-added products.

The most crucial difficulty is in finding organisms that can perform all of the required functions robustly on a variety of feedstocks after mild pretreatments. Engineering fermenting organisms that produce cellulase in sufficient quantities to completely hydrolyze the cellulosic biomass is a key development. Lowering the cost of producing these organisms is another. If the required technological advances can be achieved through genetic engineering followed by cost reductions through improved practice, then consolidated bioprocessing (or variations thereon, for inclusion in a biorefinery) can serve as a model for what might be achieved long-term in the California biomass-to-ethanol industry.

An example given in Reference D-3, for a large biomass-to-ethanol plant operating on poplar as an energy crop, if adapted to smaller plants in California using agricultural, urban, or forest wastes as feedstocks, suggests an eventual cost around 50 cents per gallon for producing ethanol, using advanced methods in a mature industry.

D 1.4 Gasification Followed by Fermentation

A different approach from the pretreatment and hydrolysis methods described above is outlined here. Gasification-fermentation first converts biomass into smaller component molecules including carbon monoxide (CO), carbon dioxide (CO_2), and hydrogen (H_2) gases by heating to suitably high temperatures. In a later stage, the process reassembles these molecules into ethanol by fermentation processes different from those described above.

The production of a mixture of CO, CO_2, H_2 and other gases, collectively called "synthesis gas", benefits from gasification technology developments over the past several decades at large-scale demonstration facilities and commercial plants operating on fossil feedstocks such as coal. After gasification of the biomass, anaerobic bacteria are used to convert the resulting synthesis gas into ethanol (C_2H_5OH). High rates of conversion are obtained because the rate-limiting process in this fermentation method is the relatively fast transfer of gas into the liquid phase compared to the rate of fermenter action on carbohydrates.

Bioengineering Resources, Inc. (BRI) has developed synthesis gas fermentation technology that can be used to produce ethanol from a variety of waste biomass feedstocks. Plans are underway to pilot the technology as a step toward commercialization. The yields can be high (a figure of 136 gallons of ethanol per ton of feedstock is projected) because all of the major biomass fractions, hemicellulose, cellulose, *and* lignin can be converted to ethanol. BRI has developed reactor systems that require less than a minute for fermentation at elevated pressure, resulting in reduced equipment costs.

D-2 Biorefineries

In the main text, we have several times referred to biorefineries designed to produce ethanol, electricity, and other chemical products from agricultural, forest, and urban wastes, as the best framework in which to establish an economically and environmentally self-sustaining California biomass-to-ethanol industry. In this section we will pull together some of these thoughts, and list some of the products that might result from a California biorefining industry.

The two more mature industries with which California waste biomass-to-ethanol must compete, Midwest corn-to-ethanol and Mideast crude oil, *rely* on refineries producing a slate of products to maintain their present cost and pricing structure. A corn-to-ethanol company producing only ethanol, or a petroleum corporation producing only gasoline for automobiles, would not survive.

In these more mature industries, the cost of the feedstocks is said to be 65%-70% of the total production costs. The chemical components must be optimally used, and the levels of production of the product streams adapted to meet current market demands. A California waste biomass-to-ethanol industry must also make the best economic uses of the chemicals in its waste feedstocks. The industry should grow to adapt its output of various products to market demand.

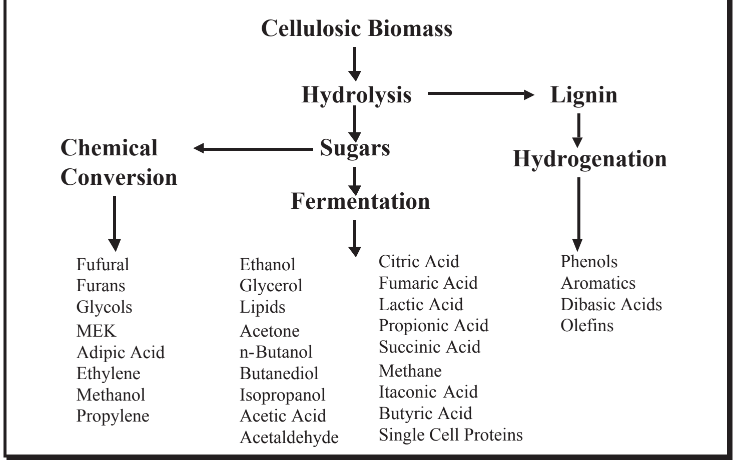
In some projects, this process has already begun. The proposed California biomass-to-ethanol plants in Chester, CA (Collins Pine project) and in Oroville, CA (Gridley project) are both collocated with existing electric power plants. The biomass plant will utilize power from the electric plant, and will supply the electric plant with lignin as a high-energy fuel. Each is a customer of the other. This synergy from cogeneration results in reduced capital and operating costs that enable both plants to be more competitive. The next step is to produce along with ethanol, a slate of other chemical products. This is proposed by the SEP project in Rio Linda, CA and also by the Collins Pine project in Chester.

The SEP project, using the Arkenol concentrated acid process on rice residues and wood wastes as the feedstocks, will produce amorphous silica from the rice straws as a co-product. The Collins Pine project using California softwoods and lumber mill wastes as feedstocks, expects to produce several chemicals (as yet unspecified) from the extractives as co-products. These co-products can significantly improve the process economics, while separating off substances to facilitate further processing of the carbohydrate streams.

The purpose of a refinery is to process all of the chemical components (fractions) to their highest and best (most profitable) end uses. For biomass, there are four major fractions: the hemicelluloses, cellulose, lignin, and extractives (defined in this section to include both organic and inorganic materials). A mature California waste-to-ethanol biorefinery should aim to make the best use of these four fractions. A chart (Figure D-3) provided by John Ferrell of the US Department of Energy, Office of Fuels Development, shows possible chemical products from the cellulose, hemicellulose, and lignin, especially illustrating the versatility of the cellulose fraction.

Figure D-3

Conversion of Biomass to Chemicals & Fuels



This discussion of the four fractions of lignocellulosic materials begins with extractives (usually less than 5% of the dry weight, but in some feedstocks, up to 25%) because these are the least-known fraction, but often the first to be separated off. Extractives from softwood wastes can be converted to high value products, some of which (terpenes, maltol, resin acids) have already been commercialized successfully. Candidate co-products include: azelaic acid for biodegradable lubricants ($4/lb.); oxyalcohols; terpenic products, such as sitosterol, a hormone precursor and texturing agent (over $100/lb.); gallic acids, which are phenol derivatives that sell for $10-$20/lb.; specialty chemicals, such as cyclotene and maltol (over $100/lb.); resin acids and their derivatives, some of which are marketed as surfactants at $5-$10/lb.; polyphenols, such as proanthocynadins, in the $100/lb. range; and pharmaceuticals from specific conifers (taxols, from Northwest yew trees are the best-known example.) (Ref. D-6)

This list is not intended to put stars in the eyes of potential owner-operators, for most waste feedstocks contain only a few weight percent in extractives; California softwoods average about 4%-5%. Even a few percent of products at the listed prices can make a significant difference in plant economics. But customers must be found and markets developed. Silica, an inorganic material that is present up to 25% in rice straw and hulls, can be viewed as "ash" or as an inorganic extractive available for potential commercialization.

The two most important fractions for the production of ethanol from biomass are the hemicelluloses (typically 15% to 30% of the dry weight) and cellulose (typically 35% to 50% of the dry weight). The hemicelluloses are easier to hydrolyze, but until recently, more difficult than cellulose to ferment to ethanol. That has changed recently with the development of bacterial enzymes that simultaneously ferment both five-carbon and six-carbon sugars (Refs. D-7, D-8, D-9) The "highest and best" use for the hemicellulose fraction of California waste biomass remains conversion into ethanol transportation fuel.

Cellulose presents more alternatives to the owner-operator. Conversion to ethanol transportation fuel is an excellent choice: it is technically feasible, environmentally desirable, and perhaps the most economically advantageous choice for a California waste biomass-to-ethanol program. Cellulose is also used to produce pulp, paper, and textiles. Cellulose derivatives, such as glucose, can be processed into a variety of useful, high volume products, including animal feeds.

A thorough assessment of alternative feedstocks by scientists and engineers from five national laboratories (Ref. D-10) identified several classes of chemicals, including organic acids (such as succinic and levulinic acids) and neutral solvents (such as butanol and acetone), that may be produced competitively from cellulosic biomass, using glucose syrup as the primary feedstock. Chemicals such as acetaldehyde, acetic acid, glycerol and isopropanol can also be produced by biomass refineries. (Ref. D-11) Adhesives, biodegradable plastics, biocompatible solvents, degradable surfactants, and enzymes may also be considered. Thus, the owner-operator of a suitably configured biomass refinery will have opportunities for diversification, if future markets dictate.

The lignin fraction (perhaps 15% -30% of the dry weight) is usually planned as an energy source for the biorefinery, or for a collocated electric power plant. This is in all likelihood, the best use for lignin in the current generation of biomass-to-ethanol plants. Other present conversions of lignin by the pulp and paper industry are to products such as dispersing agents, animal feed binders, concrete additives, drilling mud additives, and soil stabilizer. (Ref. D-2)

A biorefinery concept proposed for Quebec would produce lignin derivatives, cellulose fibers for food products, and lignin derivatives for pharmaceutical applications. (Ref. D-11) Elements of this Lignix process have been proven commercially, however, the entire process remains to be tested at the pilot plant stage. In the future, the owner-operator of a biorefinery can consider the use of some fraction of the lignin for adhesives, for particle board, for production of oxyaromatics (such as vanillin), or even possibly for octane enhancers, to advance the goals of a California clean fuel industry.

This brief summary in Section D-2 is meant to suggest that even in the short-term and especially in the mid-term, there are opportunities for entrepreneurs to benefit by developing California waste-biomass-to-ethanol facilities as biorefineries. The capital and operating costs will be higher than those for a single-product plant, reflecting the costs of equipment and labor to process the additional product streams. But, as experience in the petroleum and corn-to-ethanol industries has shown, profits will also be higher, and there will be valuable flexibility to adapt and survive profitably in changing markets.

D-3 Technology Improvements in a Mature Industry

Four technological trends leading toward the development of a profitable biomass-to-ethanol industry for California have been identified in preceding sections. These are: (1) improved pretreatment, (2) increasing use of genetically-engineered organisms with improved properties for hydrolysis and fermentation of cellulosic biomass, (3) integrating process steps to reduce capital and operating costs, and (4) producing ethanol from waste biomass in a biorefinery.

The first three trends lead to cost reductions and improved profitability through advances such as commercial-scale Simultaneous Saccharification and CoFermentation (SSCF), with possible subsequent consolidation of the key processes (including cellulase production) into a single vessel for Direct Microbial Conversion (DMC). The fourth trend encourages the best economic and environmental use of *all* chemical components of the waste biomass: hemicellulose, cellulose, lignin, organic and inorganic extractives.

Within these primary trends, there are a variety of alternative, often complementary research and development paths toward the goal of very low cost production of ethanol from waste biomass. Several of these, as listed by Prof. Lynd of Dartmouth (Ref. D-12), are reduction of milling costs, pretreatments to render cellulose more reactive, a low-cost method for recycling cellulase, and higher-temperature fermentation. A breakthrough in one such area has the potential to lessen or eliminate difficulties in other areas. This diversity of activity increases the overall probability of developing low-cost biomass-to-ethanol technology.

Approaches that have the largest economic impact reduce the cost of making biomass fermentable. Consolidated bioprocessing is the preferred strategy of Prof. Lynd, because he believes that “it offers the potential for a streamlined process that takes full advantage of the power of biotechnology for efficient and low-cost catalysis.” This path requires the development, through genetic engineering of robust microorganisms for producing cellulases, hydrolyzing carbohydrates, and fermenting five-carbon and six-carbon sugars in a single reactor.

What are the potential cost reductions for ethanol production that may result from the anticipated improvements in technology when these are incorporated into a mature biomass industry? In the literature, there are several fairly consistent estimates by respected scientists, engineers, and research organizations.

The National Renewable Energy Laboratory (Ref. D-13) has set cost reduction targets of about 50 cents per gallon for technology cost savings by the year 2005, and about 60 cents per gallon by the year 2010. On this or a somewhat longer time-scale, Drs. Lynd, Elander, and Wyman (Ref. D-3) estimate production costs of about 52 cents per gallon using consolidated bioprocessing with poplar trees as the energy crop for a very large facility.

In comparison, California has the advantage of using much lower-cost (waste) feedstocks, but may not be able to realize the advantages of scale accruing to larger plants (greater than 100 million gallons per year production). In petroleum and corn processing, about 65%-70% of the total production costs are attributable to feedstocks, so in this respect, the use of waste biomass is a significant advantage.

The above improvements in production costs are attributed to anticipated improvements in the conversion of cellulosic biomass to ethanol. They do not include the effects of producing the ethanol in a biorefinery that benefits from the production of electricity and added-value co-products. For an estimate of the impact of biorefining on a mature industry, we use values provided by Elander and Putsche in Ref. D-14 and by Katzen in Ref. D-15 for the advantage in unit production costs of (more capital-intensive) wet-milling of corn, compared to the older dry-milling process.

Wet-milling facilities are corn biorefineries. They can produce ethanol from corn at a cost 10 cents to 19 cents per gallon less than the dry-milling facilities that produce only ethanol and

DDGS. When a single figure is required, 15 cents per gallon will be used as the estimated average, long-term reduction in cost of producing ethanol, when the ethanol production is accomplished within a biorefinery, but a range of zero to 30 cents per gallon cost reduction is plausible.

One final observation: combining the estimate of 52 cents per gallon for ethanol production costs from a mature biomass-to-ethanol plant, with a reduction of perhaps 15 cents per gallon in "net feedstock costs" for the economic benefits of selling co-products from a biorefinery, results in a (most optimistic?) projection of 37 cents per gallon for delivered feedstock plus processing costs in a technologically-mature waste biomass-to-ethanol plant. Is this a reasonable estimate for total production costs in the years 2010-2020, when 65%-70% of the total costs may be those for collecting, transporting, and delivering the biomass wastes used as feedstocks? It makes 50 cents per gallon appear to be a very difficult, but perhaps achievable goal.

References for Appendix D

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Appendix E

Chapter VI

Composition and Yields of Biomass

Resources

APPENDIX E

Chapter 6

Composition And Yields Of Biomass Resources

Each of the twelve biomass Resource Categories listed in Table 6-1 contains several individual species of trees and crops, or types of municipal waste. This is detailed in Table E-1 compiled by Quang Nguyen of NREL, which presents the average compositions and theoretical ethanol yields for many of the individual feedstocks included in the Resource Categories of Table 6-1. Within these averages for each species, there is much variability, so that each individual biorefinery must perform statistical samplings adequate to characterize its intended sources of feedstock.

The glucan, mannan, and galactan in the top row of the chart are hydrolyzed to six-carbon sugars (hexoses), and the xylan and arabinan are hydrolyzed to five-carbon sugars (pentoses.) The hexoses plus pentoses sum to total carbohydrates. The sugars are then fermented to ethanol with conversion efficiencies to be discussed below.

The Theoretical Ethanol Yield given in the last column of Table E-1 (gal/OD ton is the same as gal/bdt) is the quantity of ethanol that would be produced by 100% efficient chemical conversion of the total carbohydrates, hexoses plus pentoses, to ethanol. The figures for Theoretical Ethanol Yield range from a maximum of 150.0 gal/bdt through 112.8 for mixed softwood thinnings, to 109.0 (est.) for typical municipal solid wastes (MSW), 106.3 for rice straw, down to 96.1 gal/bdt for newspaper. Potential sources such as sugar beets, algae, sewage sludge, cattle manure, and chapparal are not listed in Table E-1.

The calculation of ethanol production potentials in Table 6.1 utilizes expected yields (conversion efficiencies) for commercial systems, as provided by M. Yancey and A. Aden of the National Renewable Energy Laboratory for the 12 major Resource Categories of California waste biomass. These were provided for two time periods. The near-term yields are based on current NREL 2-stage dilute acid experimental and modeling work. The mid/far-term yield estimates are based on NREL goals for the SSCF process (1-stage dilute acid followed by enzymatic hydrolysis with simultaneous co-fermentation). The process assumptions on which these yields are based are tabulated below.

Yields for	Near-Term Conversion		Mid/Far-Term Conversion	
	Sugar Yield	Ethanol Yield	Sugar Yield	Ethanol Yield
Glucan to Glucose	60%	90%	90%	95%
Mannan to Mannose	90%	90%	85%	95%
Galactan to Galactose	90%	90%	85%	95%
Xylan to Xylose	80%	75%	85%	95%
Arabinan to Arabinose	80%	0%	85%	95%

Appendix F

Chapter VI

Locations of Solid Waste Handling Facilities in California

APPENDIX F

Chapter 6

Locations of Some Solid Waste Handling Facilities in California

The table in this Appendix was provided by the California Integrated Waste Management Board (CIWMB) from its Solid Waste Information System (SWIS) data base. The 426 entries in Table F-1 are only a fraction of the solid waste handling facilities in California. The writers of this report are grateful to several members of the CIWMB for guidance in the selection of a portion of the information available, and especially to Steve Barnett of the CIWMB Information Management Branch for compiling the data in its present form.

This table contains information on 168 large volume transfer/processing facilities, 69 material recovery facilities (MRFs, pronounced “murfs”), 187 solid waste landfills, and 2 wood waste disposal sites not contained in the preceding list. The information provided includes the activity name (one of the 4 above), waste type handled, site name and location, operator name and address. Much more information is available, including phone numbers, if one wishes to learn the capabilities and interests of the site operators. The large number of composting facilities were not included in this table of candidate sites because the waste materials are already being recycled to advantage. Their eventual uses will be determined by economic considerations.

Th large volume transfer/processing facilities serve as hubs for collection and processing. They can provide low cost, perhaps “negative cost” waste biomass feedstock if they already have, or are willing to add, the necessary sorting capabilities. MRFs are prime candidates for collocation with a biorefinery. Separation of the various categories of solid wastes is actively underway. It may be possible to customize the content of the streams to meet the process needs of an adjoining biorefinery. The owner of the MRF might be interested in becoming a partner of the combined operation.

Solid waste landfills receive a large fraction of the waste materials, but there is a State mandate to reduce the quantity of waste that will end in landfills. Some of the owner/operators of landfills may be willing to add capabilities and join in a venture that is legally defined as “diversion” of some of the materials transported to their facilities. They too may be willing to customize these sorting and processing activities to the needs of a nearby or adjacent large client biorefinery. The two wood waste disposal sites in the list are those which were not otherwise listed in the categories requested.

The types of waste included in this request are agricultural wastes, green materials, wood mill wastes, mixed municipal wastes (a large fraction), and sludge. Facilities that handle manure and various other waste categories were not requested, but the information is there in the SWIS data base. The type of wastes processed at each facility is listed in column 3 of the table. Some of the sludge will not be a good candidate to provide biomass for conversion to ethanol, because of the amount of pretreatment needed; but other sources of sludge may meet all requirements.

Paper contaminated with food waste, grease, and liquids may be unattractive for recycling, but completely appropriate for ethanol production. The same may be said of some composting materials, where the presence of small amounts of contaminants, such as plastics, may make them unattractive for recycling, but suitable for conversion to ethanol and co-products.

The list of permutations and combinations of possibilities is large. Table F-1 intends only to list locations of some of the facilities that may offer existing collection, sorting, and preprocessing infrastructure for the collocation of a biomass-to-ethanol plant. If some of these facilities can provide a "negative feedstock cost" in the near term and a very low delivered feedstock cost long-term, they are worthy of careful consideration. The owner-operator may become a partner.

Activity	Waste	Site Name	RGS	Site location	PlaceName	Operator	OperatorCity
LVT/PF	Mixed Mun	PLEASANTON GARBAGE SERVICE SW TS	P	3110 BUSCH Rd	Pleasanton	PLEASANTON GARBAGE SERVICE, INC	PLEASANTON
LVT/PF	Green Mat	DAVIS ST TRANS STA/Res RECOV COMPLX	P	2615 DAVIS St	San Leandro	OAKLAND SCAVENGER Co	OAKLAND
LVT/PF	Mixed Mun	DAVIS ST TRANS STA/Res RECOV COMPLX	P	2615 DAVIS St	San Leandro	OAKLAND SCAVENGER Co	OAKLAND
LVT/PF	Wood mill	DAVIS ST TRANS STA/Res RECOV COMPLX	P	2615 DAVIS St	San Leandro	OAKLAND SCAVENGER Co	OAKLAND
LVT/PF	Green Mat	BERKELEY Solid wst Trnsf Statn	P	1109 SECOND St	Berkeley	CITY of BERKELEY Solid wst MGMT. DIV.	BERKELEY
LVT/PF	Mixed Mun	BERKELEY Solid wst Trnsf Statn	P	1109 SECOND St	Berkeley	CITY of BERKELEY Solid wst MGMT. DIV.	BERKELEY
LVT/PF	Mixed Mun	PINE GROVE Pub Trnsf Statn	P	14390 WALNUT St	Pine Grove	A.C.E.S., INC.	Jackson
LVT/PF	Agricultural	WERN AMADOR Rec Fac	P	6500 Buena Vista Rd	Ione	AMADOR Disp SERVICES	SUTTER CREEK
LVT/PF	Mixed Mun	WERN AMADOR Rec Fac	P	6500 Buena Vista Rd	Ione	AMADOR Disp SERVICES	SUTTER CREEK
LVT/PF	Agricultural	ORD RANCH Rd Trnsf Statn	P	E of HWY 99E- ORD RANCH Rd	Gridley	NORCAL Solid wst systm - Mrysvl	Mrysvl
LVT/PF	Mixed Mun	ORD RANCH Rd Trnsf Statn	P	E of HWY 99E- ORD RANCH Rd	Gridley	NORCAL Solid wst systm - Mrysvl	Mrysvl
LVT/PF	Green Mat	OROVILLE Solid wst Trnsf Statn	P	2720 S 5th Ave	Oroville	NORCAL Solid wst systm - OROVILLE	Oroville
LVT/PF	Mixed Mun	OROVILLE Solid wst Trnsf Statn	P	2720 S 5th Ave	Oroville	NORCAL Solid wst systm - OROVILLE	Oroville
LVT/PF	Mixed Mun	AVERY Trnsf Statn	P	SEGALE Rd NEAR MORAN RD	Avery	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Agricultural	SAN ANDREAS Trnsf Statn	P	4 MI N SAN ANDREAS ON HWY 49	San Andreas	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Mixed Mun	PALOMA Trnsf Statn	P	2 MI S PALOMA ON PALOMA Rd	Paloma	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Mixed Mun	COPPEROPOLIS Trnsf Statn	P	O'BYRNES FERRY Rd	Copperopolis	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Mixed Mun	WILSEYVILLE Trnsf Statn	P	W of STORE AND POST ofF	Wilseyville	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Mixed Mun	RED HILL Trnsf Statn	P	5314 RED HILL Rd	Vallecito	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Mixed Mun	MAXWELL Trnsf Statn	P	HWY 99 NEAR MAXWELL	Maxwell	COLUSA Solid wst AND Rec, INC.	CORNING
LVT/PF	Mixed Mun	Contra Costa TS and Recvry	P	951 Waterbird Way	Martinez	BFI wst systm of North America	Los Angls
LVT/PF	Mixed Mun	CENTRAL PROCESSING Fac	P	101 Pittsburg	Richmond	W Co Res Recvry INC	RICHMOND
LVT/PF	Mixed Mun	S TAHOE REFUSE CO.,INC., T.S/MRF	P	RUTH AVE BTWN DUNLAP & 3rd St	S Lake Tahoe	S TAHOE REFUSE CO., INC.	S LAKE TAHOE
LVT/PF	Mixed Mun	WERN EL DORADO Recvry systm MRF	P	4100 Dimetrics Way	Diamond Sprg	WERN EL DORADO REG SYSTEM	Diamond Spr
LVT/PF	Mixed Mun	SHAVER LAKE Trnsf Statn	P	E of HWY 168-DINKEY CREEK RD	Shaver Lake	Co of FRESNO Pub WORKS	FRESNO
LVT/PF	Green Mat	RICE Rd RECYCLERY & Trnsf Statn	P	10463 NORTH RICE Rd	Fresno	BROWNING-FERRIS Inds of CALIF, INC	Sylmar
LVT/PF	Mixed Mun	CITY GARBAGE CO. of EUREKA Trnsf STN	P	949 W. Hawthorne St.	Eureka	CITY GARBAGE Co of EUREKA, INC.	EUREKA
LVT/PF	Mixed Mun	LEBEC INTERIM Trnsf Statn	P	300 Lfl Rd	Lebec	Co of KERN wst Mngmt DEPT.	BAKERSFIELD
LVT/PF	Mixed Mun	MCFARLAND-DELANO Trnsf Statn	P	11249 STADLEY AVE.	Bakersfield	Co of KERN wst Mngmt DEPT.	BAKERSFIELD
LVT/PF	Mixed Mun	LAKEPORT Trnsf Statn	P	910 BEVINS St	Lakeport	Co of LAKE	LAKEPORT
LVT/PF	Mixed Mun	Action Trnsf Statn	P	1449 W. Rosecrans Ave.	Gardena	RePub Services of California II, LLC	Gardena
LVT/PF	Mixed Mun	S GATE Trnsf Statn	P	9530 S GARFIELD AVENUE	S Gate	Co of Los Angls SANITATION DIST	WHITTIER
LVT/PF	Mixed Mun	CITY of SANTA MONICA Trnsf Statn	P	2500 Michigan Ave	Santa Monica	CITY of SANTA MONICA	SANTA MONICA
LVT/PF	Mixed Mun	Browning Fer Indst. Rec. & Transf.	P	2509 W ROSECRANS AVENUE	Compton	BROWNING-FERRIS Inds of CALIF, INC	Sylmar
LVT/PF	Mixed Mun	CITY of INGLEWOOD Trnsf Statn	P	222 W BEACH AVENUE	Inglewood	CITY of INGLEWOOD	INGLEWOOD
LVT/PF	Mixed Mun	BEVERLY HILLS REFUSE Trnsf Statn	P	9357 W THIRD St	Beverly Hills	CITY of BEVERLY HILLS	BEVERLY HILLS
LVT/PF	Mixed Mun	CULVER CITY Trnsf/Rec STATION	P	9255 W JEFFERSON BLVD	Culver City	CITY of CULVER CITY	CULVER CITY
LVT/PF	Mixed Mun	Downey Area Rec & Trnsf, Inc.	P	9770 Washburn Rd	Downey	CALSAN,INC	DOWNEY
LVT/PF	Mixed Mun	VAN NUYS St MDY	P	15145 OXNARD St	Van Nuys	CITY of Los Angls BUR of St MAINT	Los Angls
LVT/PF	Mixed Mun	EAST St MAINTENANCE DISTRICT YARD	P	452 SAN FERNANDO Rd	Los Angls	CITY of Los Angls BUR of St MAINT	Los Angls
LVT/PF	Mixed Mun	GRANADA HILLS St MDY	P	10210 ETIWANDA AVENUE	Northridge	CITY of Los Angls BUR of St MAINT	Los Angls
LVT/PF	Mixed Mun	SW St MDY	P	5860 S WILTON PLACE	Los Angls	CITY of Los Angls BUR of St MAINT	Los Angls
LVT/PF	Mixed Mun	PARAMOUNT Res Rec Fac	P	7230 PETTERSON LANE	Paramount	METROPOLITAN wst Disp CORP.	PARAMOUNT
LVT/PF	Mixed Mun	SERN CAL Disp Trnsf Statn	P	1908 FRANK St	Santa Monica	SERN CAL Disp	SANTA MONICA
LVT/PF	Mixed Mun	BEL-ART Trnsf Statn	P	2501 EAST 68TH St	Long Beach	ConSolidated Disp Services L.L.C.	Santa Fe Springs
LVT/PF	Mixed Mun	CARSON Trnsf Statn & MRF	P	321 W FRANCISCO St	Carson	CARSON Trnsf Statn & MRF	Torrance
LVT/PF	Mixed Mun	FALCON REFUSE CENTER, INC	P	3031 EAST "I" St	Wilmington	BFI wst systm of North America	Los Angls
LVT/PF	Mixed Mun	COMMUNITY Rec AND Res RECOV.	P	9147 DE GARMO AVENUE	Sun Valley	DE GARMO St DUMP	SUN VALLEY
LVT/PF	Mixed Mun	CENTRAL Los Angls Rec CNTR & T S	P	2201 WASHINGTON BOULEVARD	Los Angls	BLT ENTERPRISES	MONTEBELLO
LVT/PF	Mixed Mun	MISSION Rd Rec & Trnsf STATIO	P	840 S MISSION Rd	Los Angls	wst Mngmt INC - BRADLEY LF & MISS	SUN VALLEY
LVT/PF	Mixed Mun	ANGELUS WERN PAPER FIBERS, INC.	P	2474 PORTER St	Los Angls	ANGELUS WERN PAPER FIBERS, INC.	Los Angls

LVT/PF	Agricultural	NORTH FORK Trnsf Statn	P	33699 Rd 274	North Fork	MADERA Disp systm,INC.	MADERA
LVT/PF	Green Mat	NORTH FORK Trnsf Statn	P	33699 Rd 274	North Fork	MADERA Disp systm,INC.	MADERA
LVT/PF	Mixed Mun	NORTH FORK Trnsf Statn	P	33699 Rd 274	North Fork	MADERA Disp systm,INC.	MADERA
LVT/PF	Sludge	NORTH FORK Trnsf Statn	P	33699 Rd 274	North Fork	MADERA Disp systm,INC.	MADERA
LVT/PF	Mixed Mun	CASPAR Trnsf Statn	P	S END of PRAIRIE WAY	Caspar	CITY of FORT BRAGG & MENDOCINO Co	UKIAH
LVT/PF	Green Mat	Willits Solid wst Trnsf & Recy. Cen	P	350 Franklin Avenue	Willits	Solid wstS of WILLITS INC	Willits
LVT/PF	Mixed Mun	Willits Solid wst Trnsf & Recy. Cen	P	350 Franklin Avenue	Willits	Solid wstS of WILLITS INC	Willits
LVT/PF	Agricultural	ALTURAS Trnsf Statn	P	1 mile off Cty. Rd. 54 on Cty. Rd. 60	Alturas	Co of MODOC Pub WORKS DEPT	ALTURAS
LVT/PF	Mixed Mun	ALTURAS Trnsf Statn	P	1 mile off Cty. Rd. 54 on Cty. Rd. 60	Alturas	Co of MODOC Pub WORKS DEPT	ALTURAS
LVT/PF	Mixed Mun	SALINAS Disp, Trnsf & Rec	P	1120 MADISON LANE	Salinas	SALINAS Disp SERVICE, INC	SALINAS
LVT/PF	Agricultural	DEVLIN Rd Trnsf Statn	P	800 DEVLIN Rd	Napa	S NAPA wst Mngmt AUTHORITY	NAPA
LVT/PF	Mixed Mun	DEVLIN Rd Trnsf Statn	P	800 DEVLIN Rd	Napa	S NAPA wst Mngmt AUTHORITY	NAPA
LVT/PF	Mixed Mun	MCCOURTNEY Rd LARGE VOLUME T.S.	P	14741 WOLF MOUNTAIN Rd	Grass Valley	CO.of NEVADA, DEPT.of SAN. & TRANS.	NEVADA CITY
LVT/PF	Agricultural	STANTON Trnsf AND Rec CENTER #8	P	11232 KNOTT AVENUE	Stanton	CR Trnsf INC.	STANTON
LVT/PF	Mixed Mun	STANTON Trnsf AND Rec CENTER #8	P	11232 KNOTT AVENUE	Stanton	CR Trnsf INC.	STANTON
LVT/PF	Mixed Mun	RAINBOW Rec/Trnsf Statn	P	17121 NICHOLS AVENUE	Hunt Beach	RAINBOW Trnsf/Rec INC.	HUNT BEACH
LVT/PF	Wood mill	RAINBOW Rec/Trnsf Statn	P	17121 NICHOLS AVENUE	Hunt Beach	RAINBOW Trnsf/Rec INC.	HUNT BEACH
LVT/PF	Mixed Mun	CONSolidATED VOLUME TRANSPORTERS	P	1131 N. BLUE GUM St	Anaheim	Disp SERVICES, INC.	ANAHEIM
LVT/PF	Mixed Mun	SUNSET ENVIR INC TS/Res REC FAC	P	16122 CONSTRUCTION CIR W	Irvine	SUNSET ENVIRONMENTAL	IRVINE
LVT/PF	Mixed Mun	CITY of NEWPORT BEACH Trnsf Statn	P	592 SUPERIOR AVENUE	Newport Beach	CITY of NEWPORT BEACH	Newprt Bch
LVT/PF	Mixed Mun	ORANGE Res Recvry systm, INC.	P	2050 GLASSELL St	Orange	ORANGE Res Recvry systm, INC	ORANGE
LVT/PF	Mixed Mun	AUBURN PLACER Disp Trnsf Statn	P	12305 SHALE RIDGE RD	Auburn	AUBURN PLACER Disp SERVICE INC	AUBURN
LVT/PF	Mixed Mun	FORESTHILL Trnsf Statn	P	PATENT RD ofF TODD VALLEY RD	Foresthill	AUBURN PLACER Disp SERVICE INC	AUBURN
LVT/PF	Mixed Mun	MEADOW VISTA Trnsf Statn	P	COMBIE Rd AP# 72-030-02	Meadow Vista	AUBURN PLACER Disp SERVICE INC	AUBURN
LVT/PF	Mixed Mun	EAST QUINCY Trnsf Statn	P	ABERNATHY LANE	East Quincy	Co of PLUMAS	QUINCY
LVT/PF	Mixed Mun	IDYLLWILD COLLECTION STATION	P	28100 SAUNDERS MEADOW Rd	Idyllwild	Co of RIVERSIDE wst MGMT DEPT	RIVERSIDE
LVT/PF	Mixed Mun	MORENO VALLEY Trnsf & Rec FAC.	P	17700 Indian St	Moreno Valley	wst Mngmt of the Inland Valley	Hemet
LVT/PF	Green Mat	NORTH AREA Trnsf Statn	P	4450 ROSEVILLE Rd	N Highlands	Co of SACRAMENTO, Pub Works Dept.	SACRAMENTO
LVT/PF	Mixed Mun	NORTH AREA Trnsf Statn	P	4450 ROSEVILLE Rd	N Highlands	Co of SACRAMENTO, Pub Works Dept.	SACRAMENTO
LVT/PF	Wood mill	NORTH AREA Trnsf Statn	P	4450 ROSEVILLE Rd	N Highlands	Co of SACRAMENTO, Pub Works Dept.	SACRAMENTO
LVT/PF	Green Mat	S Area Trnsf Statn	P	8550 FRUITRIDGE Rd	Sacramento	Co of SACRAMENTO, Pub Works Dept.	SACRAMENTO
LVT/PF	Mixed Mun	S Area Trnsf Statn	P	8550 FRUITRIDGE Rd	Sacramento	Co of SACRAMENTO, Pub Works Dept.	SACRAMENTO
LVT/PF	Mixed Mun	HEAPS PEAK Trnsf Statn	P	HWY 18; 3 MI W of Running Springs	Lake Arrowhead		
LVT/PF	Mixed Mun	CAMP ROCK Trnsf Statn	P	CAMP ROCK Rd	Lucerne Valley	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Mixed Mun	NEWBERRY SPRINGS Trnsf Statn	P	Troy Rd and Poniente Drive	Newberry Sprngs	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Mixed Mun	Trails End(Morongo Valley)Trnsf St.	P	10780 Malibu Trail	Morongo Valley	Co of SAN BERNARDINO wst SYSTM DIV	San Bernardino
LVT/PF	Mixed Mun	Sheep Creek Trnsf Statn	P	10130 Buckwheat Rd	Phelan	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Agricultural	Twentynine Palms Trnsf Statn	P	7501 Pinto Mountain Rd	29 Palms	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Mixed Mun	Twentynine Palms Trnsf Statn	P	7501 Pinto Mountain Rd	30 Palms	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Agricultural	Trona-Argus Trnsf Statn	P	1 mi. north Argus,and 1 mi. W Trona	Trona	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Mixed Mun	Trona-Argus Trnsf Statn	P	1 mi. north Argus,and 1 mi. W Trona	Trona	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Sludge	FIESTA ISLAND SLUDGE PROCESSING	UP	FIESTA ISLAND ON MISSION BAY	San Diego	CITY of SAN DIEGO	SAN DIEGO
LVT/PF	Mixed Mun	VIEJAS Trnsf Statn	P	7850 CAMPBELL RANCH Rd	Alpine	Allied wst Inds, Inc.	San Diego
LVT/PF	Green Mat	Barrettt Jnctn Rural Cont. Station	P	1090 BARRETT LAKE Rd	Barrett Jct	Allied wst Inds, Inc.	San Diego
LVT/PF	Mixed Mun	Barrettt Jnctn Rural Cont. Station	P	1090 BARRETT LAKE Rd	Barrett Jct	Allied wst Inds, Inc.	San Diego
LVT/PF	Mixed Mun	BOULEVARD RURAL Cont. Station	P	41097 OLD HIGHWAY 80	Boulevard	Allied wst Inds, Inc.	San Diego
LVT/PF	Mixed Mun	CAMPO RURAL CONTAINER STATION	P	1515 BUCKMAN SPRGS RD	Campo	Allied wst Inds, Inc.	San Diego
LVT/PF	Mixed Mun	JULIAN RURAL CONTAINER STATION	P	500 PLEASANT VIEW DRIVE	Julian	Ramona Lfl Inc.	San Diego
LVT/PF	Mixed Mun	UNIVERSAL REFUSE REMOVAL Rec & T.S	P	1001 W. BRADLEY AVENUE	El Cajon	UNIVERSAL REFUSE REMOVAL	EL CAJON
LVT/PF	Green Mat	COAST wst Mngmt Trnsf Statn	P	5960 EL CAMINO REAL	Carlsbad	COAST wst Mngmt, INC.	CARLSBAD
LVT/PF	Mixed Mun	COAST wst Mngmt Trnsf Statn	P	5960 EL CAMINO REAL	Carlsbad	COAST wst Mngmt, INC.	CARLSBAD
LVT/PF	Mixed Mun	San FRANCISCO SLD wst TRAN & REC Ctr	P	501 Tunnel Avenue	San Francisco	Sanitry FILL Co	San Francisco

LVT/PF	Agricultural	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	CO of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
LVT/PF	Mixed Mun	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	CO of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
LVT/PF	Wood mill	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	Co of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
LVT/PF	Agricultural	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
LVT/PF	Mixed Mun	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
LVT/PF	Wood mill	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
LVT/PF	Wood mill	EAST STOCKTON Trnsf & Rec STN	P	2435 EAST WEBER AVENUE	Stockton	E STOCKTON Trnsf & RECYCLE STATION	STOCKTON
LVT/PF	Mixed Mun	STOCKTON SCAVENGER ASSOC Trnsf Stn	P	1240 NAVY DRIVE	Stockton	STOCKTON SCAVENGER ASSOC INC	STOCKTON
LVT/PF	Agricultural	TRACY Mat Recvry & T.S.	P	30703 S. MACARTHUR DRIVE	Tracy	REPETTO M	TRACY
LVT/PF	Mixed Mun	TRACY Mat Recvry & T.S.	P	30703 S. MACARTHUR DRIVE	Tracy	REPETTO M	TRACY
LVT/PF	Mixed Mun	BLUE LINE Trnsf, INC	P	180 OYSTER POINT BLVD	S San Francisco	S SAN FRANCISCO SCAVENGER CO	S San Frncisco
LVT/PF	Mixed Mun	SAN BRUNO Trnsf Statn	P	1271 MONTGOMERY AVENUE	San Bruno	SAN BRUNO GARBAGE Co, INC	SAN BRUNO
LVT/PF	Mixed Mun	MUSSEL ROCK Trnsf Statn	P	1680 EDGEWORTH AVENUE	Daly City	BROWNING-FERRIS Inds of CALIF, INC	Sylmar
LVT/PF	Mixed Mun	S BAYSIDE Trnsf Statn	P	225 SHOREWAY Rd	San CarLos	BROWNING-FERRIS Inds, SAN CARLos	SAN CARLos
LVT/PF	Agricultural	SANTA BARBARA Co Trnsf Statn	P	4430 CALLE REAL	Santa Barbara	CO of SANTA BARBARA Trnsf Statn	S Barbara
LVT/PF	Mixed Mun	SANTA BARBARA Co Trnsf Statn	P	4430 CALLE REAL	Santa Barbara	CO of SANTA BARBARA Trnsf Statn	S Barbara
LVT/PF	Green Mat	SAN MARTIN Trnsf Statn	P	14070 LLAGAS AVENUE	San Martin	S VALLEY REFUSE Disp Co	GILROY
LVT/PF	Mixed Mun	SAN MARTIN Trnsf Statn	P	14070 LLAGAS AVENUE	San Martin	S VALLEY REFUSE Disp Co	GILROY
LVT/PF	Mixed Mun	SUNNYVALE Mat & RECVR'Y & TRNSFR ST	P	301 CARL Rd	Sunnyvale	CITY of SUNNYVALE	SUNNYVALE
LVT/PF	Green Mat	Mission Trail Trnsf Statn	P	1060 RICHARD AVENUE	Santa Clara	Mission Trails wst systm	Santa Clara
LVT/PF	Green Mat	BEN LOMOND Trnsf Statn	P	9835 NEWELL CREEK Rd	Ben Lomond	Co of SANTA CRUZ	SANTA CRUZ
LVT/PF	Mixed Mun	BEN LOMOND Trnsf Statn	P	9835 NEWELL CREEK Rd	Ben Lomond	Co of SANTA CRUZ	SANTA CRUZ
LVT/PF	Agricultural	BURNEY Trnsf Statn	P	RT 229; Adjcnt to Co Rd7P200	Burney	Co of SHASTA Pub WORKS DEP	REDDING
LVT/PF	Mixed Mun	BURNEY Trnsf Statn	P	RT 229; Adjcnt to Co Rd7P201	Burney	Co of SHASTA Pub WORKS DEP	REDDING
LVT/PF	Mixed Mun	CITY of REDDING Trnsf Statn/MRF	P	2255 ABERNATHY LN	Redding	CITY of REDDING	REDDING
LVT/PF	Mixed Mun	OCCIDENTAL Trnsf Statn	P	4985 STOETZ LANE	Sebastopol		
LVT/PF	Mixed Mun	GUERNEVILLE Trnsf Statn	P	POCKET DRIVE	Guerneville		
LVT/PF	Agricultural	SONOMA Trnsf Statn	P	STAGE GULCH Rd	Sonoma		
LVT/PF	Mixed Mun	SONOMA Trnsf Statn	P	STAGE GULCH Rd	Sonoma		
LVT/PF	Mixed Mun	HEALDSBURG REFUSE Trnsf Statn	P	166 ALEXANDER VALLEY Rd	Healdsburg		
LVT/PF	Mixed Mun	ANNAPOLIS Trnsf Statn	P	33551 ANNAPOLIS Rd	Annapolis		
LVT/PF	Agricultural	TURLOCK SCAVENGER Co Trnsf STATI	P	1100 S WALNUT	Turlock	Turlock Trnsf Inc.	Turlock
LVT/PF	Mixed Mun	TURLOCK SCAVENGER Co Trnsf STATI	P	1100 S WALNUT	Turlock	Turlock Trnsf Inc.	Turlock
LVT/PF	Wood mill	TURLOCK SCAVENGER Co Trnsf STATI	P	1100 S WALNUT	Turlock	Turlock Trnsf Inc.	Turlock
LVT/PF	Agricultural	MODESTO Disp SVC TS/RES REC FAC	P	2769 W HATCH Rd	Modesto	MODESTO Disp SERVICE	MODESTO
LVT/PF	Mixed Mun	MODESTO Disp SVC TS/RES REC FAC	P	2769 W HATCH Rd	Modesto	MODESTO Disp SERVICE	MODESTO
LVT/PF	Wood mill	MODESTO Disp SVC TS/RES REC FAC	P	2769 W HATCH Rd	Modesto	MODESTO Disp SERVICE	MODESTO
LVT/PF	Agricultural	GILTON Res Recvry/Trnsf FAC	P	800 MCCLURE Rd	Modesto	GILTON Res Recvry Fac, INC.	MODESTO
LVT/PF	Mixed Mun	GILTON Res Recvry/Trnsf FAC	P	800 MCCLURE Rd	Modesto	GILTON Res Recvry Fac, INC.	MODESTO
LVT/PF	Wood mill	GILTON Res Recvry/Trnsf FAC	P	800 MCCLURE Rd	Modesto	GILTON Res Recvry Fac, INC.	MODESTO
LVT/PF	Agricultural	BERTOLOTTI Trnsf & Rec CENTER	P	231 FLAMINGO DRIVE	Modesto	BERTOLOTTI Trnsf & Rec	CERES
LVT/PF	Mixed Mun	BERTOLOTTI Trnsf & Rec CENTER	P	231 FLAMINGO DRIVE	Modesto	BERTOLOTTI Trnsf & Rec	CERES
LVT/PF	Wood mill	BERTOLOTTI Trnsf & Rec CENTER	P	231 FLAMINGO DRIVE	Modesto	BERTOLOTTI Trnsf & Rec	CERES
LVT/PF	Green Mat	BURNT RANCH Trnsf St	P	HWY. 299, W. of BURNT RANCH	Burnt Ranch	Co of TRINITY	Weaverville
LVT/PF	Mixed Mun	BURNT RANCH Trnsf St	P	HWY. 299, W. of BURNT RANCH	Burnt Ranch	Co of TRINITY	Weaverville
LVT/PF	Mixed Mun	HAYFORK Trnsf St	P	EAST HWY 3; S of FAIRGROUNDS	Hayfork	Co of TRINITY	Weaverville
LVT/PF	Sludge	HAYFORK Trnsf St	P	EAST HWY 3; S of FAIRGROUNDS	Hayfork	Co of TRINITY	Weaverville
LVT/PF	Green Mat	HOBEL Trnsf Statn	P	HIGHWAY 3 S of TRINITY CENTER	Trinity Center	Co of TRINITY	Weaverville
LVT/PF	Mixed Mun	HOBEL Trnsf Statn	P	HIGHWAY 3 S of TRINITY CENTER	Trinity Center	Co of TRINITY	Weaverville
LVT/PF	Agricultural	RUTH Trnsf St	P	S of Ruth Res. Adjcnt state Hiwy	Ruth	Co of TRINITY	Weaverville
LVT/PF	Mixed Mun	RUTH Trnsf St	P	S of Ruth Res. Adjcnt state Hiwy	Ruth	Co of TRINITY	Weaverville
LVT/PF	Green Mat	VAN DUZEN Trnsf Statn	P	CO Rd 511, VAN DUZEN Rd	Mad River	Co of TRINITY	Weaverville

LVT/PF	Mixed Mun	VAN DUZEN Trnsf Statn	P	CO Rd 511, VAN DUZEN Rd	Mad River	Co of TRINITY	Weaverville
LVT/PF	Agricultural	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
LVT/PF	Green Mat	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
LVT/PF	Mixed Mun	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
LVT/PF	Mixed Mun	CAL SIERRA Trnsf Statn	P	19309 INDUSTRIAL DRIVE	Sonora	CAL SIERRA Disp, INC.	STANDARD
LVT/PF	Mixed Mun	GOLD COAST Rec Fac	P	5275 COLT St	Ventura (S Bnvnt)	GOLD COAST Rec INC.	VENTURA
LVT/PF	Agricultural	DEL NORTE REGIONAL Rec & Trnsf	P	111 S Del Norte Blvd.	Oxnard	BLT ENTERPRISES of OXNARD, INC.	Oxnard
LVT/PF	Mixed Mun	DEL NORTE REGIONAL Rec & Trnsf	P	111 S Del Norte Blvd.	Oxnard	BLT ENTERPRISES of OXNARD, INC.	Oxnard
LVT/PF	Green Mat	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
LVT/PF	Mixed Mun	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
LVT/PF	Wood mill	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
LVT/PF	Mixed Mun	PONDEROSA Trnsf Statn	P	PONDEROSA WAY	Brownsville	YUBA SUTTER Disp, INC.	Mrysvl
MRF		WADHAM ENERGY, LTD.	E		Colusa		
MRF		MT DIABLO PAPER STOCK & Rec CENTER	UP	4080 MALLARD DR	Concord	CONTRA COSTA wst SERVICES, INC.	CONCORD
MRF	Mixed Mun	Rec CENTER & Trnsf Statn	P	1300 LOVERIDGE Rd	Pittsburg	CONTRA COSTA wst SERVICES, INC.	CONCORD
MRF	Mixed Mun	WERN EL DORADO Recvry systm MRF	P	4100 Dimetrics Way	Diamond Springs	WERN EL DORADO REG SYSTEM	Diamond Spr
MRF	Mixed Mun	JEFFERSON AVENUE Trnsf Statn	P	5608 VILLA AVENUE	Fresno	WERN wst Inds/wst MGMT	TORRANCE
MRF	Wood mill	JEFFERSON AVENUE Trnsf Statn	P	5608 VILLA AVENUE	Fresno	WERN wst Inds/wst MGMT	TORRANCE
MRF	Green Mat	TEHACHAPI Rec, INC	P	416 N DENNISON RD	Tehachapi	BENZ SANITATION SERVICE	TEHACHAPI
MRF	Mixed Mun	TEHACHAPI Rec, INC	P	416 N DENNISON RD	Tehachapi	BENZ SANITATION SERVICE	TEHACHAPI
MRF		MORTON Rec (MRI)	TBD	E/2, S34,T12N,R23W SBBM	Maricopa	MORTON Rec INC	TAFT
MRF	Agricultural	KCWMA wst PROCESSING Fac	P	7803 HANFORD-ARMONA RD.	Hanford	Co of KINGS WST Mngmt AUTH	HANFORD
MRF	Mixed Mun	KCWMA wst PROCESSING Fac	P	7803 HANFORD-ARMONA RD.	Hanford	Co of KINGS WST Mngmt AUTH	HANFORD
MRF	Wood mill	KCWMA wst PROCESSING Fac	P	7803 HANFORD-ARMONA RD.	Hanford	Co of KINGS WST Mngmt AUTH	HANFORD
MRF	Mixed Mun	East Los Angls Rec and Trnsf	P	1512 N. Bonnie Beach Place	City Terrace	Perdomo/BLT Enterprises L.L.C.	Oxnard
MRF	Mixed Mun	wst Recvry AND Rec Fac	P	4489 ARDINE St	S Gate	H.B.J.J. Inc. Subsidiary of USA wst	Bell Gardens
MRF	Mixed Mun	Coastal Mat Recvry Fac & TS	P	357 W. Compton Blvd.	Gardena	SI-NOR Inc. DBA: Coastal MRF & TS	Gardena
MRF	Mixed Mun	RAIL CYCLE Com Mat Recvry Fac	P	6300 E. 26TH St	Commerce	wst Mngmt INC	Gardena
MRF	Mixed Mun	CITY RUBBISH Co	P	1511 FISHBURN AVENUE	City Terrace	CITY RUBBISH Co	Los Angls
MRF	Mixed Mun	United wst Rec & Trnsf, Inc.	P	14048 E. Valley Blvd.	Industry	United wst Rec & Trnsf Inc.	Industry
MRF		CITY of POMONA MRF	TBD	2000-2200 Pomona Blvd.	Pomona		
MRF	Mixed Mun	MAMMOTH Rec Fac AND TS	P	21739 Rd 19	Chowchilla	MADERA Disp systm,INC.	MADERA
MRF	Wood mill	MARIN Sanitry SERVICE Trnsf Statn	P	1060 ANDERSEN DRIVE	San Rafael	MARIN Sanitry SERVICE	SAN RAFAEL
MRF		MRWMD Mat Recvry Fac	P	14201 Del Monte Blvd	Marina	Co of MONTEREY REGIONAL wst MGT	MARINA
MRF	Mixed Mun	NAPA GARBAGE SERVICE MRF	P	SE of end of Tower Rd, Hwy 29	Napa	NAPA GARBAGE SERVICE	NAPA
MRF	Mixed Mun	EASTERN REGIONAL MRF	P	3 miles S of Truckee, CA	Alpine Meadows	EASTERN REGIONAL Lfl INC	Tahoe
MRF	Sludge	EASTERN REGIONAL MRF	P	3 miles S of Truckee, CA	Alpine Meadows	EASTERN REGIONAL Lfl INC	Tahoe
MRF	Mixed Mun	PERRIS Mat Recvry Fac	P	1706 GOETZ Rd	Perris	CR&R INCORPORATED	STANTON
MRF	Mixed Mun	Robert A Nelson Trnsf Statn & MRF	P	Agua Mansa Rd W of Brown Ave	Rubidoux	AGUA MANSA MRF, LLC	FONTANA
MRF	Agricultural	Elder Creek Recvry and Trnsf Statio	P	8642 Elder Creek Rd	Sacramento	California wst Revoval Inds, Inc	Lodi
MRF	Green Mat	Elder Creek Recvry and Trnsf Statio	P	8642 Elder Creek Rd	Sacramento	California wst Revoval Inds, Inc	Lodi
MRF	Mixed Mun	Elder Creek Recvry and Trnsf Statio	P	8642 Elder Creek Rd	Sacramento	California wst Revoval Inds, Inc	Lodi
MRF	Agricultural	FOLSOM Mat Recvry & Compsting	P	N of NEW FOLSOM PRISON	Represa (Folsom)	PRISON INDUSTRY AUTHORITY, ST. of CAL	FOLSOM
MRF	Mixed Mun	FOLSOM Mat Recvry & Compsting	P	N of NEW FOLSOM PRISON	Represa (Folsom)	PRISON INDUSTRY AUTHORITY, ST. of CAL	FOLSOM
MRF	Mixed Mun	ADVANCE Disp Mat RECVRY FACLTY	P	17105 MESA Rd	Hesperia	ADVANCE Disp Co	HESPERIA
MRF	Mixed Mun	W VALLEY Mat RECVR'Y Fac	P	9401 N. ETIWANDA AVENUE	Fontana	BURRTEC wst Inds, INC.	FONTANA
MRF	Mixed Mun	VICTOR VALLEY MRF & Trnsf Statn	P	NW CORNER of ABBY LN & B St	Victorville	BURRTEC wst Inds, INC.	FONTANA
MRF	Mixed Mun	ESCONDIDO Res Recvry	P	1044 W. WASHINGTON AVENUE	Escondido	JEMCO EQUIPMENT CORPORATION	RAMONA
MRF	Green Mat	EDCO STATION	P	8132 COMMERCIAL St	La Mesa	EDCO Disp CORPORATION	Lemon Grove
MRF	Mixed Mun	EDCO STATION	P	8132 COMMERCIAL St	La Mesa	EDCO Disp CORPORATION	Lemon Grove
MRF	Mixed Mun	FALLBROOK Rec Fac	Pd	550 W. AVIATION Rd	Fallbrook	FALLBROOK REFUSE SERVICE	FALLBROOK
MRF	Green Mat	RAMONA MRF AND Trnsf Statn	P	324 MAPLE St	Ramona	RAMONA Disp SERVICE	RAMONA

MRF	Mixed Mun	RAMONA MRF AND Trnsf Statn	P	324 MAPLE St	Ramona	RAMONA Disp SERVICE	RAMONA
MRF	Green Mat	wst ResS TECHNOLOGY, INC., R$T.S.	P	895 EGBERT St	San Francisco	wst ResS TECHNOLOGY, INC.	San Francisco
MRF	Mixed Mun	wst ResS TECHNOLOGY, INC., R$T.S.	P	895 EGBERT St	San Francisco	wst ResS TECHNOLOGY, INC.	San Francisco
MRF	Mixed Mun	W COAST Rec Co	P	1900 17TH St	San Francisco	W COAST RECYCYCLING Co	San Francisco
MRF	Agricultural	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	Co of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
MRF	Mixed Mun	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	Co of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
MRF	Wood mill	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	Co of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
MRF	Agricultural	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
MRF	Mixed Mun	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
MRF	Wood mill	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
MRF	Wood mill	EAST STOCKTON Trnsf & Rec STN	P	2435 EAST WEBER AVENUE	Stockton	E STOCKTON Trnsf & RECYCLE STATION	STOCKTON
MRF	Agricultural	TRACY Mat Recvry & T.S.	P	30703 S. MACARTHUR DRIVE	Tracy	REPETTO M	TRACY
MRF	Mixed Mun	TRACY Mat Recvry & T.S.	P	30703 S. MACARTHUR DRIVE	Tracy	REPETTO M	TRACY
MRF	Green Mat	ZANKER Rd CLASS III Lfl	P	705 Los ESTEROS RD	San Jose	Zanker Rd Res Mngmt, Limited	San Jose
MRF	Green Mat	BFI's RECYCLERY	P	1601 DIXON LANDING Rd	San Jose	INTERNATIONAL Disp CORPORATION	MILPITAS
MRF	Mixed Mun	BFI's RECYCLERY	P	1601 DIXON LANDING Rd	San Jose	INTERNATIONAL Disp CORPORATION	MILPITAS
MRF	Green Mat	Greenwst Recvry Fac	P	625 Charles St	San Jose	Zanker Rd Res Mngmt, Limited	San Jose
MRF	Mixed Mun	CITY of REDDING Trnsf Statn/MRF	P	2255 ABERNATHY LN	Redding	CITY of REDDING	REDDING
MRF	Agricultural	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
MRF	Green Mat	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
MRF	Mixed Mun	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
MRF	Mixed Mun	CAL SIERRA Trnsf Statn	P	19309 INDUSTRIAL DRIVE	Sonora	CAL SIERRA Disp, INC.	STANDARD
MRF	Mixed Mun	GOLD COAST Rec Fac	P	5275 COLT St	Ventura (S Bnvt)	GOLD COAST Rec INC.	VENTURA
MRF		DEL NORTE REGIONAL Rec & Trnsf	P	111 S Del Norte Blvd.	Oxnard	BLT ENTERPRISES of OXNARD, INC.	Oxnard
MRF	Agricultural	DEL NORTE REGIONAL Rec & Trnsf	P	111 S Del Norte Blvd.	Oxnard	BLT ENTERPRISES of OXNARD, INC.	Oxnard
MRF	Mixed Mun	DEL NORTE REGIONAL Rec & Trnsf	P	111 S Del Norte Blvd.	Oxnard	BLT ENTERPRISES of OXNARD, INC.	Oxnard
MRF	Green Mat	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
MRF	Mixed Mun	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
MRF	Wood mill	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
SWL	Green Mat	TRI CITIES Rec & Disp FAC	P	7010 AUTO MALL PARKWAY	Fremont	OAKLAND SCAVENGER Co	OAKLAND
SWL	Sludge	TRI CITIES Rec & Disp FAC	P	7010 AUTO MALL PARKWAY	Fremont	OAKLAND SCAVENGER Co	OAKLAND
SWL	Green Mat	ALTAMONT Lfl & Res RECV'RY	P	10840 ALTAMONT PASS Rd	Livermore	wst Mngmt of ALAMEDA Co	OAKLAND
SWL	Green Mat	VASCO Rd Sanitry Lfl	P	4001 NORTH VASCO Rd	Livermore	BROWNING-FERRIS Inds of CALIF, INC	Sylmar
SWL	Agricultural	Amador Co SLF/B Vista Cls II Lfl	P	6500 Buena Vista Rd	Ione	A.C.E.S., INC.	Jackson
SWL	Sludge	Amador Co SLF/B Vista Cls II Lfl	P	6500 Buena Vista Rd	Ione	A.C.E.S., INC.	Jackson
SWL	Agricultural	ROCK CREEK Lfl	P	12021 HUNT Rd	Milton	Co of CALAVERAS	S ANDREAS
SWL	Sludge	ROCK CREEK Lfl	P	12021 HUNT Rd	Milton	Co of CALAVERAS	S ANDREAS
SWL	Agricultural	STONYFORD Disp St	P	LODOGA/STONYFORD RD	Stonyford	Co of COLUSA Pub WORKS	COLUSA
SWL	Agricultural	W CONTRA COSTA Lfl	P	PARR BLVD & GARDEN TRACT RD	Richmond	W CONTRA COSTA Sanitry Lfl INC	RICHMOND
SWL	Sludge	W CONTRA COSTA Lfl	P	PARR BLVD & GARDEN TRACT RD	Richmond	W CONTRA COSTA Sanitry Lfl INC	RICHMOND
SWL	Green Mat	ACME Lfl	P	WATERBIRD WY	Martinez	ACME FILL CORPORATION	MARTINEZ
SWL	Agricultural	KELLER CANYON Lfl	P	901 BAILEY Rd	Mulligan Hill	KELLER CANYON Lfl	PACHECO
SWL	Sludge	KELLER CANYON Lfl	P	901 BAILEY Rd	Mulligan Hill	KELLER CANYON Lfl	PACHECO
SWL	Agricultural	CRESCENT CITY Lfl	P	Hights Access Rd off Old Mill	Crescent City	DEL NORTE Solid wst MGMT. AUTH.	CRESCENT C
SWL	Sludge	CRESCENT CITY Lfl	P	Hights Access Rd off Old Mill	Crescent City	DEL NORTE Solid wst MGMT. AUTH.	CRESCENT C
SWL	Wood mill	CRESCENT CITY Lfl	P	Hights Access Rd off Old Mill	Crescent City	DEL NORTE Solid wst MGMT. AUTH.	CRESCENT C
SWL	Agricultural	UNION MINE Disp St	P	5700 UNION MINE Rd	El Dorado	EL DORADO Lfl, INC.	Diamond Spr.
SWL	Sludge	UNION MINE Disp St	P	5700 UNION MINE Rd	El Dorado	EL DORADO Lfl, INC.	Diamond Spr.
SWL	Agricultural	COALINGA Disp St	P	E of Hwy 198 & Alcade on Lost Hills	Coalinga	Co of FRESNO Pub WORKS	FRESNO
SWL	Agricultural	AMERICAN AVENUE Disp St	P	18950 W AMERICAN AV 4	Tranquillity	Co of FRESNO Pub WORKS	FRESNO
SWL	Wood mill	ORANGE AVENUE Disp INC	P	3280 S ORANGE AVE	Fresno	ORANGE AVENUE Disp, INC.	FRESNO
SWL	Agricultural	GLENN Co Lfl St	P	5 MI W of I-5 ON CO RD 33	Artois	Co of GLENN Pub WORKS, JOHN JOYCE	WILLOWS

SWL	Sludge	CUMMINGS Rd Lfl	P	END of CUMMINGS Rd	Eureka	CUMMINGS Rd Lfl	EUREKA
SWL	Agricultural	CALEXICO Solid wst Disp St	P	NEW RIVER & HWY 98	Calexico	Co of IMPERIAL Pub WORKS	EL CENTRO
SWL	Agricultural	REPub IMPERIAL Lfl	P	104 EAST ROBINSON Rd	Imperial	REPub IMPERIAL ACQUISITION CORP.	IMPERIAL
SWL	Agricultural	LONE PINE Disp St	P	CEMETERY Rd; E of TOWN	Lone Pine	Co of INYO INTEGRATED wst MGMT.	BISHOP
SWL	Agricultural	INDEPENDENCE Disp St	P	RD E of HWY 395; 1.25 MI S of town	Independence	Co of INYO INTEGRATED wst MGMT.	BISHOP
SWL	Wood mill	INDEPENDENCE Disp St	P	RD E of HWY 395; 1.25 MI S of town	Independence	Co of INYO INTEGRATED wst MGMT.	BISHOP
SWL	Agricultural	BISHOP SUNLAND	P	Sunland Dr & Sunland Indian Rs Rd	Bishop	Co of INYO INTEGRATED wst MGMT.	BISHOP
SWL	Sludge	BISHOP SUNLAND	P	Sunland Dr & Sunland Indian Rs Rd	Bishop	Co of INYO INTEGRATED wst MGMT.	BISHOP
SWL	Agricultural	ARVIN Sanitry Lfl	P	WHEELER RIDGE RD	Arvin	Co of KERN wst Mngmt DEPT.	Bakersfield
SWL	Agricultural	LosT HILLS Sanitry Lfl	P	14251 HOLLOWAY Rd	Lost Hills	Co of KERN wst Mngmt DEPT.	Bakersfield
SWL	Agricultural	KERN VALLEY Sanitry Lfl	P	9800 SIERRA WAY	Kernville	Co of KERN wst Mngmt DEPT.	Bakersfield
SWL	Agricultural	MOJAVE-ROSAMOND Sanitry Lfl	P	400 SILVER QUEEN Rd	Mojave	Co of KERN wst Mngmt DEPT.	Bakersfield
SWL	Agricultural	RIDGECREST-INYOKERN Sanitry Lfl	P	3301 BOWMAN Rd	Ridgecrest	Co of KERN wst Mngmt DEPT.	Bakersfield
SWL	Green Mat	EDWARDS AFB-MAIN BASE Lfl	P	EDWARDS A F B	Edwards AFB	US DEPT of AIR FORCE-EDWARDS AFB	EDWARDS AFB
SWL	Agricultural	AVENAL Lfl	P	201 NORTH HYDRIL Rd	Avenal	CITY of AVENAL	AVENAL
SWL	Agricultural	HANFORD Sanitry Lfl	P	SE HWY 43 & HANFORD-ARMONA rd	Hanford	Co of KINGS wst Mngmt AUTHORI	HANFORD
SWL	Wood mill	HANFORD Sanitry Lfl	P	SE HWY 43 & HANFORD-ARMONA rd	Hanford	Co of KINGS wst Mngmt AUTHORI	HANFORD
SWL	Agricultural	BASS HILL Lfl	P	HWY 395 JOHNSTONVILLE AREA	Johnstonville	Co of LASSEN Pub WORKS DEPT	SUSANVILLE
SWL	Sludge	BASS HILL Lfl	P	HWY 395 JOHNSTONVILLE AREA	Johnstonville	Co of LASSEN Pub WORKS DEPT	SUSANVILLE
SWL	Agricultural	HERLONG Disp Fac	P	Co Rd 328	Herlong	Co of LASSEN Pub WORKS DEPT	SUSANVILLE
SWL	Agricultural	SCHOLL CANYON Sanitry Lfl	P	3001 SCHOLL CANYON Rd	Glendale	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Wood mill	SCHOLL CANYON Sanitry Lfl	P	3001 SCHOLL CANYON Rd	Glendale	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Agricultural	wst Mngmt of LANCASTER S LF	P	600 EAST AVENUE "F"	Lancaster	wst Mngmt of CALIFORNIA INC	LANCASTER
SWL	Agricultural	CHIQUITA CANYON Sanitry Lfl	P	29201 HENRY MAYO DRIVE	Valencia (S Clarita)	RePub Services of California I, L.L.C	Santa Fe Spr
SWL	Sludge	CHIQUITA CANYON Sanitry Lfl	P	29201 HENRY MAYO DRIVE	Valencia (S Clarita)	RePub Services of California I, L.L.C	Santa Fe Spr
SWL	Agricultural	PUENTE HILLS Lfl #6	P	2800 S WORKMAN MILL RD	Whittier	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Sludge	PUENTE HILLS Lfl #6	P	2801 S WORKMAN MILL RD	Whittier	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Wood mill	PUENTE HILLS Lfl #6	P	2802 S WORKMAN MILL RD	Whittier	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Agricultural	CALABASAS Sanitry Lfl	P	5300 LosT HILLS Rd	Agoura Hills	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Wood mill	CALABASAS Sanitry Lfl	P	5300 LosT HILLS Rd	Agoura Hills	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Sludge	PEBBLY BEACH (AVALON) Disp St	P	DUMP Rd	Avalon	SEAGULL SANITATION systm	Santa Fe Spr
SWL	Wood mill	PEBBLY BEACH (AVALON) Disp St	P	DUMP Rd	Avalon	SEAGULL SANITATION systm	Santa Fe Spr
SWL	Agricultural	FAIRMEAD Solid wst Disp St	P	AVENUE 22 AT Rd 19	Chowchilla	MADERA Disp systm,INC.	MADERA
SWL	Green Mat	FAIRMEAD Solid wst Disp St	P	AVENUE 22 AT Rd 19	Chowchilla	MADERA Disp systm,INC.	MADERA
SWL	Sludge	FAIRMEAD Solid wst Disp St	P	AVENUE 22 AT Rd 19	Chowchilla	MADERA Disp systm,INC.	MADERA
SWL	Agricultural	REDWOOD Sanitry Lfl	P	NE NOVATO BTWN Santonio & RR	Novato	REDWOOD Lfl INC. SANIFILL	HOUSTON
SWL	Sludge	REDWOOD Sanitry Lfl	P	NE NOVATO BTWN Santonio & RR	Novato	REDWOOD Lfl INC. SANIFILL	HOUSTON
SWL	Wood mill	REDWOOD Sanitry Lfl	P	NE NOVATO BTWN Santonio & RR	Novato	REDWOOD Lfl INC. SANIFILL	HOUSTON
SWL	Sludge	MARIPOSA Co Sanitry Lfl	P	Dump Rd 2 MI N of Mariposa -Hwy 49	Mariposa	Co of MARIPOSA	MARIPOSA
SWL	Wood mill	UKIAH Solid wst Disp St	P	VICHY Springs rd 3 MI SW of Ukiah	Ukiah	CITY of UKIAH	UKIAH
SWL	Green Mat	HIGHWAY 59 Disp St	P	HWY 59; 6 MI N MERCED	Merced	Co of MERCED	MERCED
SWL	Wood mill	HIGHWAY 59 Disp St	P	HWY 59; 6 MI N MERCED	Merced	Co of MERCED	MERCED
SWL	Agricultural	BILLY WRIGHT Disp St	P	BILLY WRIGHT RD; 7 MI W Los Banos	Los Banos	Co of MERCED	MERCED
SWL	Sludge	ALTURAS Sanitry Lfl	P	INTERSECTION of CO #54 & #60	Alturas	Co of MODOC Pub WORKS DEPT	ALTURAS
SWL	Agricultural	WALKER Sanitry Lfl	P	EAST SIDE LANE	Walker	Co of MONO	BRIDGEPORT
SWL	Sludge	WALKER Sanitry Lfl	P	EAST SIDE LANE	Walker	Co of MONO	BRIDGEPORT
SWL	Green Mat	PUMICE VALLEY Lfl	P	HWY 120; 4 MI S MONO LAKE	Lee Vining	Co of MONO	BRIDGEPORT
SWL	Sludge	PUMICE VALLEY Lfl	P	HWY 120; 4 MI S MONO LAKE	Lee Vining	Co of MONO	BRIDGEPORT
SWL	Green Mat	BENTON CROSSING Sanitry Lfl	P	1 MI SW BENTON CROSSING	Benton	Co of MONO	BRIDGEPORT
SWL	Sludge	BENTON CROSSING Sanitry Lfl	P	1 MI SW BENTON CROSSING	Benton	Co of MONO	BRIDGEPORT
SWL	Green Mat	BENTON Sanitry Lfl	P	HWY 120 & STATE ROUTE 6	Benton	Co of MONO	BRIDGEPORT
SWL	Agricultural	LEWIS Rd Sanitry Lfl	P	LEWIS RD;2 MI W WATSNVLL	Pajaro	RURAL DISPOS-ALL SERVICE	SALINAS

SWL	Agricultural	JOHNSON CANYON Sanitry Lfl	P	2 MI E HWY 101 Johnson Canyon Rd	Gonzales	Salinas Valley Solid wst Authority	Salinas
SWL	Sludge	JOHNSON CANYON Sanitry Lfl	P	3 MI E HWY 101 Johnson Canyon Rd	Gonzales	Salinas Valley Solid wst Authority	Salinas
SWL	Agricultural	JOLON Rd Sanitry Lfl	P	3 MI S KING CITY	King City	JOLON Rd Lfl Co	KING CITY
SWL	Agricultural	CRAZY HORSE Sanitry Lfl	P	CRAZY HORSE N of PRUNEDALE	Prunedale	RURAL DISPOS-ALL SERVICE	SALINAS
SWL	Agricultural	Mont Regional Wst Mgmt Dst/Mar	P	2 MI N of MARINA; D MONTE BLVD	Marina	CO of MONTEREY REGIONAL wst MGT	MARINA
SWL	Sludge	Mont Regional Wst Mgmt Dst/Mar	P	3 MI N of MARINA; D MONTE BLVD	Marina	Co of MONTEREY REGIONAL wst MGT	MARINA
SWL	Agricultural	CLOVER FLAT Lfl	P	4380 SILVERADO Trl/3MI SE of CALS	Napa	UPPER VALLEY Rec & Disp SERVIC	ST HELENA
SWL	Sludge	CLOVER FLAT Lfl	P		Napa	UPPER VALLEY Rec & Disp SERVIC	ST HELENA
SWL	Agricultural	SANTIAGO CANYON Sanitry Lfl	P	3099 SANTIAGO CANYON Rd	Irvine	Co of ORANGE INTEG wst MGT DEPT	SANTA ANA
SWL	Agricultural	OLINDA ALPHA Sanitry Lfl	P	NE of VALENCIA A & Carbon CYN RD	Brea	Co of ORANGE INTEG wst MGT DEPT	SANTA ANA
SWL	Wood mill	OLINDA ALPHA Sanitry Lfl	P	NE of VALENCIA A & Carbon CYN RD	Brea	CO of ORANGE INTEG wst MGT DEPT	SANTA ANA
SWL	Sludge	WERN REGIONAL Lfl	P	3195 ATHENS Rd AP #17-060-02	Lincoln	W PLACER wst MGT AUTHORITY	Auburn
SWL	Agricultural	BADLANDS Disp St	P	31125 IRONWOOD AVE	Moreno Valley	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	LAMB CANYON Disp St	P	Lamb CANYON rd 3 MI S of Beaumnt	Beaumont	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	EDOM HILL Disp St	P	70-100 Edom Hill Rd	Cathedral City	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	ANZA Sanitry Lfl	P	40329 TERWILLIGER RD	Anza	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	OASIS Sanitry Lfl	P	84-505 84TH St	Oasis	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	DESERT CTR L.F.(EAGLE MOUNT)	P	7991 KAISER Rd	Desert Center	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	BLYTHE Sanitry Lfl	P	1000 MIDLAND RD	Blythe	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Sludge	METROPOLITAN WATER DISTRICT	E	33740 BOREL Rd	Winchester	SKINNER FILTRATION PLANT	WINCHESTER
SWL	Agricultural	MECCA Lfl II	P	BOX CANYON RD & GARFIELD ST	Mecca	CO of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Sludge	SACRAMENTO Co Lfl (KIEFER)	P	12701 KIEFER BLVD	Rancho Cordova	CO of SACRAMENTO, Pub Works Dept.	Sacramento
SWL	Green Mat	DIXON PIT Lfl	P	8973 ELK GROVE - FLORIN Rd	Elk Grove	Super Pallet Rec Corporation	Elk Grove
SWL	Green Mat	L & D Lfl CO	P	8635 FRUITRIDGE Rd	Sacramento	L & D Lfl CO	Sacramento
SWL	Wood mill	John Smith Rd Class III Lfl	P	2650 John Smith Rd	Hollister	CO of SAN BENITO Pub WORKS DEPT	HOLLISTER
SWL	Wood mill	PFIZER, INC. Lucerne Val. INERT D.S.	E	1/4 MI w of Pfizer Lucerne Val plnt	Lucerne Valley	PFIZER INC.	Lucerne Val
SWL	Sludge	CALIFORNIA St Lfl	P	END of CALIFORNIA St	Redlands	CITY of REDLANDS	REDLANDS
SWL	Agricultural	VICTORVILLE REFUSE Disp St	P	5 MI N of Victrvll on Stoddard Wells	Victorville	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Sludge	VICTORVILLE REFUSE Disp St	P	6 MI N of Victrvll on Stoddard Wells	Victorville	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Agricultural	BARSTOW REFUSE Disp St	P	Barstow Rd 3 MI S of BARSTOW	Barstow	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Sludge	BARSTOW REFUSE Disp St	P	Barstow Rd 3 MI S of BARSTOW	Barstow	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Agricultural	COLTON REFUSE Disp St	P	Tropica Rancho 1/2 Mi w of La Cdna	Colton	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Sludge	COLTON REFUSE Disp St	P	Tropica Rancho 1/2 Mi w of La Cdna	Colton	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Wood mill	COLTON REFUSE Disp St	P	Tropica Rancho 1/2 Mi w of La Cdna	Colton	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Sludge	LANDERS Disp St	P	WINTERS RD; 4.1 MI E of HWY 247	Landers	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Sludge	Resrv COMPONENT TRAINING Ctr	P	FORT IRWIN MILITARY BASE	Fort Irwin (Mil Res)	US DEPT of ARMY-FORT IRWIN	FORT IRWIN
SWL	Wood mill	Mitsubishi Cement Plnt Cushenbury Llf	P	5808 STATE HIGHWAY 18	Lucerne Valley	MITSUBISHI CEMENT CORP	Lucerne Val
SWL	Agricultural	RAMONA Lfl	P	20630 PAMO RD	Ramona	Allied wst Inds, Inc.	San Diego
SWL	Sludge	RAMONA Lfl	P	20630 PAMO RD	Ramona	Allied wst Inds, Inc.	San Diego
SWL	Wood mill	RAMONA Lfl	P	20630 PAMO RD	Ramona	Allied wst Inds, Inc.	San Diego
SWL	Agricultural	BORREGO SPRINGS Lfl	P	2449 PALM CAYNON Rd	Borrego Springs	Allied wst Inds, Inc.	San Diego
SWL	Sludge	BORREGO SPRINGS Lfl	P	2449 PALM CAYNON Rd	Borrego Springs	Allied wst Inds, Inc.	San Diego
SWL	Wood mill	BORREGO SPRINGS Lfl	P	2449 PALM CAYNON Rd	Borrego Springs	Allied wst Inds, Inc.	San Diego
SWL	Agricultural	OTAY Sanitry Lfl	P	1700 MAXWELL RD	Otay (Chula Vista)	CO of SAN DIEGO Solid wst DIV	SAN DIEGO
SWL	Sludge	OTAY Sanitry Lfl	P	1700 MAXWELL RD	Otay (Chula Vista)	CO of SAN DIEGO Solid wst DIV	SAN DIEGO
SWL	Wood mill	OTAY Sanitry Lfl	P	1700 MAXWELL RD	Otay (Chula Vista)	CO of SAN DIEGO Solid wst DIV	SAN DIEGO
SWL	Agricultural	OTAY ANNEX Lfl	P	1700 MAXWELL RD	Chula Vista	Allied wst Inds, Inc.	San Diego
SWL	Green Mat	OTAY ANNEX Lfl	P	1700 MAXWELL RD	Chula Vista	Allied wst Inds, Inc.	San Diego
SWL	Sludge	OTAY ANNEX Lfl	P	1700 MAXWELL RD	Chula Vista	Allied wst Inds, Inc.	San Diego
SWL	Sludge	SYCAMORE Sanitry Lfl	P	8514 MAST BOULEVARD	Santee (San Diego)	Allied wst Inds, Inc.	San Diego
SWL	Green Mat	FRENCH CAMP Lfl	P	4599 S. MANTHEY Rd @ Downing A	Stockton	CITY of STOCKTON Pub WORKS	STOCKTON
SWL	Agricultural	FOOTHILL Sanitry Lfl	P	6484 NORTH WAVERLY Rd	Linden	FOOTHILL Sanitry Lfl INC	STOCKTON

SWL	Wood mill	FOOTHILL Sanitry Lfl	P	6484 NORTH WAVERLY Rd	Linden	FOOTHILL Sanitry Lfl INC	STOCKTON
SWL	Agricultural	FORWARD, INC	P	9999 S. Austin Rd	Manteca	FORWARD, INC.	STOCKTON
SWL	Sludge	FORWARD, INC	P	10000 S. Austin Rd	Manteca	FORWARD, INC.	STOCKTON
SWL	Agricultural	CITY of PASO ROBLES Lfl	P	HWY 46; 8 MI E of PASO ROBLES	Paso Robles	CITY of PASO ROBLES	Paso Robles
SWL	Sludge	CITY of PASO ROBLES Lfl	P	HWY 46; 8 MI E of PASO ROBLES	Paso Robles	CITY of PASO ROBLES	Paso Robles
SWL	Agricultural	COLD CANYON Lfl Solid wst DS	P	2268 CARPENTER CANYON Rd	San Luis Obispo	COLD CANYON Lfl, INC	S Luis Obispo
SWL	Agricultural	CHICAGO GRADE Lfl	P	HOMESTEAD Rd	Atascadero	JOHNSON W	TEMPLETON
SWL	Sludge	OX MOUNTAIN Sanitry Lfl	P	2 MI N-E 1/2 MOON BY ofF HWY 92	Half Moon Bay	BROWNING-FERRIS IND of CA, INC	Sylmar
SWL	Agricultural	FOXEN CANYON Sanitry Lfl	P	1.5 MI N Los Olivos FOXEN CYN RD	Los Olivos	CO of S BARBARA Pub WORKS DEP	S. Barbara
SWL	Sludge	VANDENBERG AFB Lfl	P	VANDENBERG AFB	Vandenberg AFB	US Dept. of the Air Force, 30 CES/CEVCC	Vandenbrg AFB
SWL	Agricultural	TAJIGUAS Sanitry Lfl	P	HWY 101; 23 MI W S.BARBARA	Goleta	Co of S. BARBARA Pub WORKS DEP	S. Barbara
SWL	Sludge	TAJIGUAS Sanitry Lfl	P	HWY 101; 23 MI W S.BARBARA	Goleta	Co of S. BARBARA Pub WORKS DEP	S. Barbara
SWL	Agricultural	City of SANTA MARIA Refuse Disp St	P	2065 EAST MAIN St	Santa Maria	CITY of SANTA MARIA	SANTA MARIA
SWL	Green Mat	City of SANTA MARIA Refuse Disp St	P	2065 EAST MAIN St	Santa Maria	CITY of SANTA MARIA	SANTA MARIA
SWL	Sludge	CITY of LOMPOC Sanitry Lfl	P	700 S AVALON Rd	Lompoc	CITY of LOMPOC Pub WORKS DEPT	LOMPOC
SWL	Agricultural	PACHECO PASS Sanitry Lfl	P	3665 PACHECO PASS HWY	Gilroy	S VALLEY REFUSE Disp CO	GILROY
SWL	Sludge	PACHECO PASS Sanitry Lfl	P	3665 PACHECO PASS HWY	Gilroy	S VALLEY REFUSE Disp CO	GILROY
SWL	Wood mill	PACHECO PASS Sanitry Lfl	P	3665 PACHECO PASS HWY	Gilroy	S VALLEY REFUSE Disp CO	GILROY
SWL	Sludge	NEWBY ISLAND Sanitry Lfl	P	1601 DIXON LANDING Rd	San Jose	INTERNATIONAL Disp CORP	MILPITAS
SWL	Green Mat	ZANKER Rd CLASS III Lfl	P	705 Los Esteros Rd Nr ZANKER RD	San Jose	Zanker Rd Res Man, Ltd	San Jose
SWL	Green Mat	KIRBY CANYON Recy. Disp Fac.	P	910 Coyote Creek Golf Drive	San Jose	wst Mngmt of CA Inc	Morgan Hill
SWL	Green Mat	GUADALUPE Sanitry Lfl	P	15999 GUADALUPE MINES Rd	San Jose	GUADALUPE RUBBISH DISPCO, INC	SAN JOSE
SWL	Sludge	CITY of SANTA CRUZ Sanitry Lfl	P	605 DIMEO LANE	Santa Cruz	CITY of SANTA CRUZ	SANTA CRUZ
SWL	Agricultural	CITY of WATSONVILLE Lfl	P	San Andreas rd S of BUENA VISTA	Watsonville	CITY of WATSONVILLE	Watsonville
SWL	Sludge	CITY of WATSONVILLE Lfl	P	San Andreas rd S of BUENA VISTA	Watsonville	CITY of WATSONVILLE	Watsonville
SWL	Agricultural	BUENA VISTA DRIVE Sanitry Lfl	P	150 ROUNDTREE LANE	Watsonville	Co of SANTA CRUZ	SANTA CRUZ
SWL	Green Mat	BUENA VISTA DRIVE Sanitry Lfl	P	150 ROUNDTREE LANE	Watsonville	Co of SANTA CRUZ	SANTA CRUZ
SWL	Sludge	BUENA VISTA DRIVE Sanitry Lfl	P	150 ROUNDTREE LANE	Watsonville	Co of SANTA CRUZ	SANTA CRUZ
SWL	Agricultural	ANDERSON Solid wst Disp St	P	18703 CAMBRIDGE Rd	Anderson	Anderson Solid wst, Inc.	Anderson
SWL	Sludge	ANDERSON Solid wst Disp St	P	18703 CAMBRIDGE Rd	Anderson	Anderson Solid wst, Inc.	Anderson
SWL	Wood mill	ANDERSON Solid wst Disp St	P	18703 CAMBRIDGE Rd	Anderson	Anderson Solid wst, Inc.	Anderson
SWL	Agricultural	W CENTRAL Lfl	P	14095 CLEAR CREEK Rd	Redding	CO of SHASTA Pub WORKS DEP	REDDING
SWL	Sludge	W CENTRAL Lfl	P	14095 CLEAR CREEK Rd	Redding	CO of SHASTA Pub WORKS DEP	REDDING
SWL	Sludge	BLACK BUTTE Solid wst Disp St	P	3 MI N MOUNT SHASTA CITY	Mount Shasta	Co of SISKIYOU Pub WORKS DEPT	YREKA
SWL	Agricultural	B & J DROPBOX Sanitry Lfl	P	6426 HAY Rd; 1/4 MI W HWY 113	Vacaville	B & J DROP BOX, INC.	Vacaville
SWL	Sludge	B & J DROPBOX Sanitry Lfl	P	6426 HAY Rd; 1/4 MI W HWY 113	Vacaville	B & J DROP BOX, INC.	Vacaville
SWL	Agricultural	POTRERO HILLS Lfl	P	3675 Potrero Hills Lane	Suisun City	POTRERO HILLS Lfl,INC.	FAIRFIELD
SWL	Sludge	POTRERO HILLS Lfl	P	3675 Potrero Hills Lane	Suisun City	POTRERO HILLS Lfl,INC.	FAIRFIELD
SWL	Sludge	EASTERLY wst WATER Treatmnt Plnt	E	VACA STATION Rd	Elmira	CITY of VACAVILLE Pub WORKS/UTIL	ELMIRA
SWL	Agricultural	CENTRAL Lfl	P	500 MEACHAM Rd	Petaluma		
SWL	Sludge	CENTRAL Lfl	P	500 MEACHAM Rd	Petaluma		
SWL	Wood mill	CENTRAL Lfl	P	500 MEACHAM Rd	Petaluma		
SWL	Agricultural	FINK Rd Lfl	P	4000 FINK Rd	Crows Landing	Stanislaus Co Dept. of Pub Works	Crows Landing
SWL	Sludge	FINK Rd Lfl	P	4000 FINK Rd	Crows Landing	Stanislaus Co Dept. of Pub Works	Crows Landing
SWL	Agricultural	RED BLUFF Sanitry Lfl	P	19995 PLYMIRE Rd; 2 MI nw Red Bluf	Red Bluff	CO of TEHAMA Pub WORKS DEPT	GERBER
SWL	Green Mat	RED BLUFF Sanitry Lfl	P	19996 PLYMIRE Rd; 2 MI nw Red Bluf	Red Bluff	CO of TEHAMA Pub WORKS DEPT	GERBER
SWL	Agricultural	WEAVERVILLE Lfl Disp St	P	1.5 MI NE WEAVERVILLE ofF HWY 3	Weaverville	Co of TRINITY	WEAVERVILLE
SWL	Green Mat	WEAVERVILLE Lfl Disp St	P	1.5 MI NE WEAVERVILLE ofF HWY 3	Weaverville	Co of TRINITY	WEAVERVILLE
SWL	Agricultural	TEAPOT DOME Disp St	P	AVENUE 128 AND Rd 208	Porterville	Co of TULARE	VISALIA
SWL	Agricultural	WOODVILLE Disp St	P	RD 152 AT AVE 198; 10 MI SE Tulare	Tulare	Co of TULARE	VISALIA
SWL	Agricultural	VISALIA Disp St	P	Rd 80 AT AVENUE 332	Visalia	Co of TULARE	VISALIA
SWL	Agricultural	TOLAND Rd Sanitry Lfl	P	3500 NORTH TOLAND Rd	Santa Paula	Ventura Reg. Santation Dist	VENTURA

SWL	Sludge	TOLAND Rd Sanitry Lfl	P	3500 NORTH TOLAND Rd	Santa Paula	Ventura Reg. Santation Dist	VENTURA
SWL	Sludge	SIMI VALLEY Lfl & Rec CENTER	P	111 W Los Angls AVENUE	Simi Valley	Wst MAN of CA Simi Val	SIMI VALLEY
SWL	Agricultural	YOLO Co CENTRAL Lfl	P	COUNTRY Rd 28H & Cntry rd 104	Davis		
SWL	Sludge	YOLO Co CENTRAL Lfl	P	COUNTRY Rd 28H & Cntry rd 105	Davis		
SWL	Agricultural	UNIV of CALIF DAVIS Sanitry Lfl	P	W END UCD CAMPUS ON CO RD 98	Davis	U of CA, DAVIS PHYSICAL PLANT	DAVIS
SWL	Sludge	UNIV of CALIF DAVIS Sanitry Lfl	P	W END UCD CAMPUS ON CO RD 99	Davis	U of CA, DAVIS PHYSICAL PLANT	DAVIS
SWL	Agricultural	OSTROM Rd Lfl	P	OSTROM RD. 5 MI E. of HWY. 65	Wheatland	YUBA SUTTER Disp, INC.	Mrysvl
SWL	Sludge	OSTROM Rd Lfl	P	OSTROM RD. 5 MI E. of HWY. 65	Wheatland	YUBA SUTTER Disp, INC.	Mrysvl
WWDS	Wood mill	LOUISIANA-PACIFIC Lfl	P	btwn Baggett Mrysvl Rd & Ophir Rd	Oroville	LOUISIANA PACIFIC CORP- RED BLUFF	RED BLUFF
WWDS	Wood mill	Harwood Prod. Wood wst Disp St	P	1/2 MI N of BRANSCOMB	Branscomb	HARWOOD PRODUCTS	BRANSCOMB

		TBD =to be determ
LVT/PF	Large Volume Trnsf/Proc Fac	P = Permitted
MRF	Mat Recvry Fac	Pd = Proposed
WWDS	Wood wst Disp St	UP = Unpermitted
SWL	Solid wst Lfl	E= Exempt

Appendix G

Chapter VII

Feestock Evaluation Costs and Evaluation of

Ethanol Production Costs

Appendix G

Chapter 7
Evaluation of Feedstock Costs

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1.0 Introduction

Providing sufficient feedstocks for to produce ethanol is a significant constraint for most biomass to ethanol plants that could be built in California. While biomass resources are plentiful, the quantities required for a plant that produces over 20 million gallons per year of ethanol exceed 200,000 tons per year (bone dry ton (BDT basis). Constraints on supply and transportation distances become significant when the combination of available feedstocks, transportation costs, seasonal availability, and competing uses for feedstocks are taken into consideration.

This report analyzes potential biomass feedstocks prices for ethanol production and describes scenarios for ethanol production from biomass. The composition and price of feedstocks are estimated. Transportation costs are determined for various size ethanol plants. The amount of feedstock required for ethanol production is then determined for different plant size scenarios.

Four categories of biomass feedstocks were considered for the Evaluation of Biomass-To-Ethanol Fuel Potential in California. This Appendix provides the assumptions on feedstocks costs used in Chapter VIII, Economic Evaluation. The following four feedstock categories were analyzed:

- Forest Material
- Agricultural Residue
- Urban Waste
- Energy Crops

Table 1-1 shows ethanol production scenarios that were considered for economic analysis in Appendix G. A mix of feedstock materials was estimated for each feedstock category. The effect of plant size affected several elements of the feedstock cost. Transportation costs increased as feedstock costs increased. In addition, limits on the availability of some feedstocks requires a change in the feedstock mix as ethanol production capacity increases.

This Appendix discusses the following:

- Feedstock Description
- Feedstock Costs
- Transportation Costs
- Resource Constraints

Table 1-1. Summary of Ethanol Plant Scenarios

Feedstock Category	Technology	Plant Type	Timeframe/capacity (MM gal/yr) near	mid	mid	long
Subsidy for fraction of feedstock			Yes	Yes	No	No
Forest Material	2-stage dilute acid	grass roots		20, 40, 60	40	30
Forest Material	2-stage dilute acid	co-located	20	20, 40, 60	40	30
Forest Material	acid/enzyme	grass roots		40	40	30
Forest Material	acid/enzyme	co-located	20	40	40	30
Ag Residue	2-stage dilute acid	grass roots		20, 40, 60	40	30
Ag Residue	2-stage dilute acid	co-located	20	20, 40, 60	40	30
Ag Residue	acid/enzyme	grass roots		40	40	30
Ag Residue	acid/enzyme	co-located	20	40	40	30
Urban/Mixed	2-stage dilute acid	grass roots		30, 50, 80	50	30
Urban/Mixed	2-stage dilute acid	co-located		30, 50, 80	50	30
Urban/Mixed	acid/enzyme	grass roots		50	50	30, 80, 200
Urban/Mixed	acid/enzyme	co-located		50	50	30
Dedicated Crops	2-stage dilute acid	grass roots				30
Dedicated Crops	2-stage dilute acid	co-located				30
Dedicated Crops	acid/enzyme	grass roots				30, 80, 200
Dedicated Crops	acid/enzyme	co-located				30

2.0 Feedstock Description

A mix of materials was estimated for different categories of biomass feedstocks. Four feedstock categories are a composite of the materials shown in Table 2-1. The fraction of each material was estimated from available resources as discussed in Chapter 3.

Properties of the feedstock materials are shown in Table 2-2. The properties, based on analyses performed by NREL, include sugars, lignin, and ash. The table also shows the maximum theoretical yield for ethanol production for each material. Higher lignin and ash content reduces the ethanol yield. The highest theoretical yields correspond to paper with a high cellulose content and very low lignin content. Rice straw has the lowest theoretical yield due to its high ash content. Several feedstock materials (waste paper, yard waste, urban wood waste, and other agricultural waste) are assumed themselves to be comprised of several materials. Properties for these component materials are shown in Table 2-3.

Based on the feedstock material fractions and on an estimated practical yield for ethanol production for each material, the amount of needed feedstock material was calculated for each scenario. These values are shown in Table 2-4.

Table 2-2. Feedstock properties

Feedstock Category	Material	(Percent dry weight of unextracted feedstock)								(kg/metric ton BD feedstock)			(gal/BD ton)
		Glucan	Mannan	Galactan	Xylan	Arabinan	Total Lignin	Ash	Extractive	Total Hexose	Total Pentose	Total Carbohydrate	Theoretical Ethanol Yield
Forest Material	Lumbermill Waste	43.3	10.2	2.8	7.4	1.5	28.6	0.9	5	625.5	101.1	726.6	112.8
	Forest Slash/ Thinnings	43.3	10.2	2.8	7.4	1.5	28.6	0.9	5	625.5	101.1	726.6	112.8
Agricultural Residue	Rice Straw	32	0.2	0.9	13.8	3.4	13.1	25		367.7	195.4	563.1	87.4
	Orchard Prunings	31.2	1.4	0.8	20.5	1.9	31.2	5.8		371.1	254.5	625.5	97.1
	Other Agricultural Waste	35	4.5	1.3	16.2	1.8	30.2	4.2		453.1	204.4	657.4	102.0
Urban Waste	Waste Paper	63	2.8	0.3	7.4	0.5	13.5	9.8	0	734.4	89.3	823.7	127.8
	Newsprint	44.3	4.9	0.6	5.2	0.6	29.3	3.5	0	553.3	65.9	619.2	96.1
	Tree Prunings	35	4.5	1.3	16.2	1.8	30.2	4.2		453.1	204.4	657.4	102.0
	Urban Wood Waste	37.9	7.4	2.5	12.4	2.2	29.1	2.6	2.4	530.8	166.5	697.4	108.2
	Yard Waste	34.2	2.3	0.4	14.1	1.9	18.2	20		410.0	181.8	591.7	91.8
Energy Crop	Eucalyptus	36.8	2.2	1	19	1.4	28.8	1.2	9.7	444.3	231.4	675.7	104.9

Table 2-3. Estimated compositions of composite feedstock materials

Material	Component	(Percent dry weight of unextracted feedstock)								(kg/metric ton BD feedstock)			(gal/BD ton)
		Glucan	Mannan	Galactan	Xylan	Arabinan	Total Lignin	Ash	Extractive	Total Hexose	Total Pentose	Total Carbohydrate	Theoretical Ethanol Yield
Waste Paper	100%	62.99	2.78	0.33	7.41	0.45	13.53	9.82	0	734.4	89.3	823.7	127.8
Un-coated Free Sheet	30%	74.9	2.7	0.3	8.9	0	5.3	7.7		865.5	101.1	966.6	150.0
Packaging Papers	40%	66.2	3.2	0.6	6.6	0.6	15.6	0.7		777.7	81.8	859.5	133.4
Coated Paper	30%	46.8	2.3	0	7	0.7	19	24.1		545.5	87.5	633.0	98.2
Tree Chips/Other Agricultural Waste	100%	35.01	4.46	1.31	16.18	1.81	30.21	4.15	0	453.1	204.4	657.4	102.0
Almond tree prunings	70%	31.2	1.4	0.8	20.5	1.9	31.2	5.8		371.1	254.5	625.5	97.1
Radiata pine	30%	43.9	11.6	2.5	6.1	1.6	27.9	0.3		644.4	87.5	731.9	113.6
Urban Wood Waste	100%	37.9	7.4	2.5	12.4	2.2	29.1	2.6	2.4	530.8	166.5	697.4	108.2
White oak prunings		34.2	2.3	0.4	14.1	1.9	18.2	20		410.0	181.8	591.7	91.8
CO Douglas fir (debarked)	20%	43.6	13.3	4.5	6.4	4.7	24.6	0.3	4.4	682.2	126.1	808.3	125.4
CA Ponderosa pine (whole tree)	20%	42.6	10.5	3.3	7.4	1.5	28.5	0.7	4.1	626.6	101.1	727.7	112.9
CA White fir (whole tree)	20%	40.7	10.4	3.2	7.3	1.2	29.9	0.6	3.3	603.3	96.6	699.8	108.6
Almond tree prunings	40%	31.2	1.4	0.8	20.5	1.9	31.2	5.8		371.1	254.5	625.5	97.1
Yard Waste	Assume white oak prunings	34.2	2.3	0.4	14.1	1.9	18.2	20		410.0	181.8	591.7	91.8

Table 2-1. Estimated mixture of materials for model biomass feedstocks

Forest Material	**Timeframe**				
	Near	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Mix (%)**				
Lumbermill Waste	37	39	19	13	27
Forest Slash/Thinnings	63	61	81	87	73

Agricultural Residue	**Timeframe**					
	Near	**Mid**	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Mix (%)**					
Other Agricultural Waste	20	20	20	30	20	20
Rice Straw	50	50	50	30	50	50
Orchard Prunings	30	30	30	40	30	30

Urban Waste	**Timeframe**						
	Mid	**Mid**	**Mid**	**Mid**	**Long**	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Mix (%)**						
Segregated Waste Paper	54	54	0	58	54	58	80
Yard Waste	8	8	30	8	8	8	4
Urban Wood Waste	21	21	30	17	21	17	8
Landscape/Tree Prunings	17	17	40	17	17	17	8

Energy Crops	**Timeframe**		
	Long	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Estimated Feedstock Mix (%)**		
Eucalyptus	100	100	100

The compositional data do not sum to 100 percent. It is believed that some inert material or extractives are not included and that the sugar fractions of the feedstock are accurately determined. The sugar and lignin fractions were held constant and additional ash and extractives were assumed for the economic analysis in Appendix G.

Table 2-4. Feedstock material tonnage required for each scenario

Forest Material	Timeframe				
	Near	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Tonnage (thousand BD tons)**				
Lumbermill Waste	100	100	100	100	100
Forest Slash/Thinnings	161	157	414	671	270

Agricultural Residue	Timeframe					
	Near	Mid	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Tonnage (thousand BD tons)**					
Other Agricultural Waste	57	57	114	170	170	82
Rice Straw	166	166	332	199	498	238
Orchard Prunings	90	90	179	239	269	129

Urban Waste	Timeframe						
	Mid	Mid	Mid	Mid	Long	Long	Long
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Tonnage (thousand BD tons)**						
Segregated Waste Paper	184	306	0	526	176	504	1739
Yard Waste	38	63	237	101	36	97	121
Urban Wood Waste	84	141	201	182	81	175	205
Landscape/Tree Prunings	72	121	284	193	69	185	218

Energy Crops	Timeframe		
	Long	Long	Long
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Feedstock Tonnage**		
Eucalyptus	397	1060	2649

Forest material

Forest material consists of lumbermill waste, forest thinnings, and residues from logging operations (forest slash). Compositions for forest material were assumed to be the same as the composition for the Quincy Library Group (QLG) mix of feedstocks shown in Table 2-2. This QLG project plans to use a mix of forest materials (Yancey).

Ethanol plants using forest material feedstock were assumed to be located next to a lumbermill, and would use the waste from that lumbermill (assumed to be 100,000 BDT/year) as feedstock material. The remainder of the feedstock would consist of forest thinnings and forest slash.

Agricultural residue

Plants operating on agricultural residue were assumed to use a mixture of orchard prunings, rice straw, and other agricultural waste. Orchard prunings are currently used as fuel for biomass power plants. The prunings consist of tree branches that are removed seasonally as well as removals of entire orchards. Constraints on agricultural burning help make this material available

Urban waste

A mixture of urban wood waste, tree prunings, yard waste, and waste paper are urban waste feedstocks that could be used for ethanol production. Clean wood waste is currently collected for use as a feedstock for particle board manufacturing. Most urban wood waste that is currently burned in biomass power plants consists of larger branches from tree pruning and removal with very little clean wood residue from furniture and lumber operations. Urban wood waste is a limited resource for existing biomass power plants and if used as an ethanol feedstock the price and transportation distance would increase. If lignin from ethanol production proves to be a suitable fuel for biomass power plants, the lignin could replace some or all of the feedstock for power plants and eliminate the potential competition for a limited resource.

Chipped tree branches and yard waste are another potential feedstock. These materials are either composted or used for landfill cover and are not suitable as fuels for biomass power plants. Sorting and quality control steps may need to be taken with branches and yard waste as these can quickly rot, may contain unexpected contaminants, and can have a high ash content

Waste paper could may also be available from material recovery facilities which serve as separation and transfer stations for urban waste. Locating the ethanol plant at such a facility would reduce transport costs and disposal costs.

Many waste streams such as office waste contain a high portion of waste paper. The paper that is not recycled is more likely to be contaminated with foodwaste, grease, liquids, and other materials but still useable for ethanol production. There are not many competing uses for contaminated paper. Such facilities may hand up to 360 tons of paper per year. This quantity is sufficient for a small ethanol plant. Supplemental feedstocks such as yard waste and tree chips as well as urban wood waste, if available, would provide sufficient material for a 30 MM gal/year plant.

Energy crops

This study used eucalyptus as the energy crop in the economic analysis, based primarily on its ability to grow well without irrigation. Another potential advantage of eucalypus (and other woody crops) is that bioremediation of groundwater contamination may allow for a dual use, which would improve the economics. Energy crops with irrigation requirements, such as hybrid poplar and sugar-based crops such as sugar beets, sweet sorghum, and sugar cane, were not considered.

3.0 Feedstock Costs

Of the variables evaluated, the cost of the feedstock has a very important effect on the economics of ethanol production. Production economics were analyzed for feedstocks with and without subsidies shown in Table 8-2 in the main report. Materials that could potentially be subsidized (forest thinnings, rice straw, and waste paper) were estimated to make up 30 to 70 percent of the feedstock from an ethanol plant.

The cost of feedstocks was obtained from several sources. CEC documented the results of a biomass feedstock model for DOE in 1994 (Tiangco 1998). This study uses a cost of production model to determine the cost of forest material, energy crops, rice straw, and other biomass materials. The costs estimates are based on a life cycle analysis of labor, land, fuel, financing, and equipment costs. CEC and NREL also completed a study of biomass. This study examines recent biomass feedstocks that might be suitable for ethanol production.

Table 3-1 summarizes the cost for biomass feedstock materials, excluding transportation costs. Table 3-2 shows feedstock costs including transportation costs. (Transportation costs are discussed in Section 4 of this Appendix.) The potential subsidy that was estimated for each feedstock is shown in Table 3-3. The total value of feedstock subsidies, and the value per gallon of ethanol produced, varies with plant size. Figures 3-1 and 3-2 show this variation resulting from a $30/BD ton forest thinning subsidy for plants using forest material feedstock in $/year and $/gal, respectively. Tables 3-3 and 3-4 show the same information for a waste paper subsidy for ethanol plants using urban waste feedstock. Costs for each of the four categories of feedstock materials were estimated as a composite of the mix of available feedstocks in Table 3-5.

With the forest materials case, forest thinnings supplement lumbermill waste as a feedstock. Lumbermill waste is valued at $20/ton if a biomass power plant is co-located with the ethanol plant and $5/ton for a stand alone ethanol plant. The lumbermill waste would either need to be transported or used for lower value purposes if no biomass plant were available to use this material. Forest thinnings are more expensive and add to the cost of the feedstock. Subsidized forest thinnings were considered as feedstocks since efforts are currently underway to use forest thinning practices as a means of reducing fire risk. Other competing uses for forest thinings could raise the price of the material; however, very large quantities are under consideration for ethanol production.

Some rice straw qualifies for a tax credit if it is reused. This fraction of the agricultural material feedstocks was considered as one that could potentially qualify for continued subsidies. Orchard prunings are also used as feedstocks for biomass power plants. The use of this material for ethanol production could cause an increase in the price for such materials unless the supply is carefully assessed.

Table 3-1. Feedstock material cost (without transportation cost)

Forest Material	Timeframe				
	Near	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Cost ($/BD ton)**				
Lumbermill Waste	20	2.5/20[1]	2.5/20[1]	2.5/20[1]	2.5/20[1]
Forest Slash/Thinnings	34	34	34	34	34

Agricultural Residue	Timeframe					
	Near	Mid	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Cost ($/BD ton)**					
Other Agricultural Waste	5	5	5	5	5	5
Rice Straw	18	18	18	18	18	18
Orchard Prunings	23	23	23	23	23	23

Urban Waste	Timeframe						
	Mid	Mid	Mid	Mid	Long	Long	Long
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Cost ($/BD ton)**						
Segregated Waste Paper	10	20	N/A	60	60	60	60
Yard Waste	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Urban Wood Waste	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Landscape/Tree Prunings	5	5	5	5	5	5	5

Energy Crops	Timeframe		
	Long	Long	Long
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Estimated Feedstock Cost ($/BD ton)**		
Eucalyptus	36	36	36

[1]$2.5/BD ton for grass roots plant, $20/BD ton for co-located plant.

Table 3-2. Feedstock material cost (including transportation cost)

Forest Material	Timeframe				
	Near	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Cost ($/BD ton)**				
Lumbermill Waste	20	2.5/20[1]	2.5/20[1]	2.5/20[1]	2.5/20[1]
Forest Slash/Thinnings	43.6	43.5	47.5	50.4	45.5

Agricultural Residue	Timeframe					
	Near	Mid	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Cost ($/BD ton)**					
Other Agricultural Waste	13.4	13.4	13.4	13.4	13.4	13.4
Rice Straw	27.9	27.9	30.1	28.4	31.7	28.9
Orchard Prunings	31	31	31	31	31	31

Urban Waste	Timeframe						
	Mid	Mid	Mid	Mid	Long	Long	Long
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Cost ($/BD ton)**						
Segregated Waste Paper	10/64.9[2]	30/65.7	N/A	66.8	60/64.9[2]	66.8	70.1
Yard Waste	2.5/9.2[3]	10.2	10.2	11.7	2.5/9.2[3]	11.7	16.2
Urban Wood Waste	10.5/17.6[4]	18.6	18.6	20.2	10.5/17.6[4]	20.2	24.9
Landscape/Tree Prunings	5/12.1[5]	13.1	13.1	14.7	5/12.1[5]	14.7	19.4

Energy Crops	Timeframe		
	Long	Long	Long
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Estimated Feedstock Cost ($/BD ton)**		
Eucalyptus	41.8	43.6	46.3

[1] $2.5/BD ton for stand alone plant, $20/BD ton for co-located plant.
[2] $10 to 30/BD ton for stand alone plant, $64.9/BD ton for co-located plant.
[3] $2.5/BD ton for grass roots plant, $9.2/BD ton for co-located plant.
[4] $10.5/BD ton for grass roots plant, $17.6/BD ton for co-located plant.
[5] $5/BD ton for grass roots plant, $12.1/BD ton for co-located plant.

Table 3-3. Feedstock material subsidy

Forest Material	Timeframe				
	Near	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Subsidy ($/BD ton)**				
Lumbermill Waste	0	0	0	0	0
Forest Slash/Thinnings	30	30	0/30[1]	30	0

Agricultural Residue	Timeframe					
	Near	**Mid**	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Subsidy ($/BD ton)**					
Other Agricultural Waste	0	0	0	0	0	0
Rice Straw	15	15	15	0	15	0
Orchard Prunings	0	0	0	0	0	0

Urban Waste	Timeframe						
	Mid	**Mid**	**Mid**	**Mid**	**Long**	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Subsidy ($/BD ton)**						
Segregated Waste Paper	0	30	N/A	30	0	30	0
Yard Waste	0	0	0	0	0	0	0
Urban Wood Waste	0	0	0	0	0	0	0
Landscape/Tree Prunings	0	0	0	0	0	0	0

Energy Crops	Timeframe		
	Long	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Estimated Feedstock Subsidy ($/BD ton)**		
Eucalyptus	0	0	0

[1]Both subsidy and non-subsidy scenarios were analyzed.

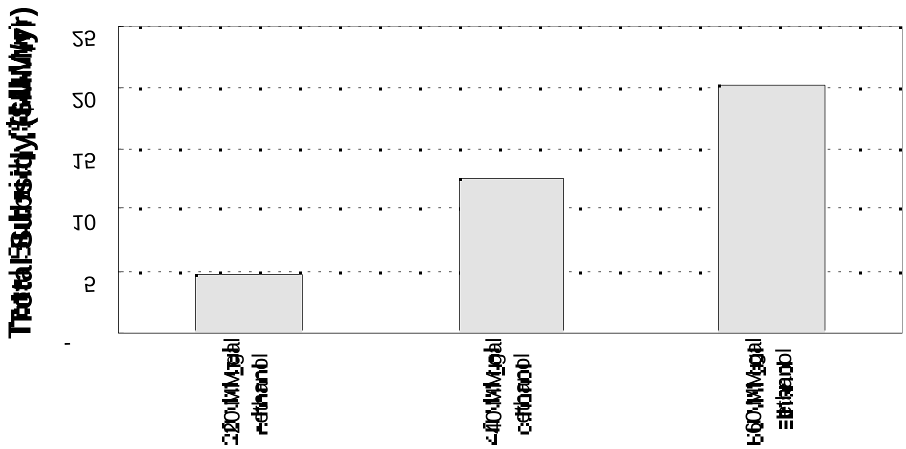

Figure 3-1. Annual subsidy value for ethanol plants using forest material feedstock

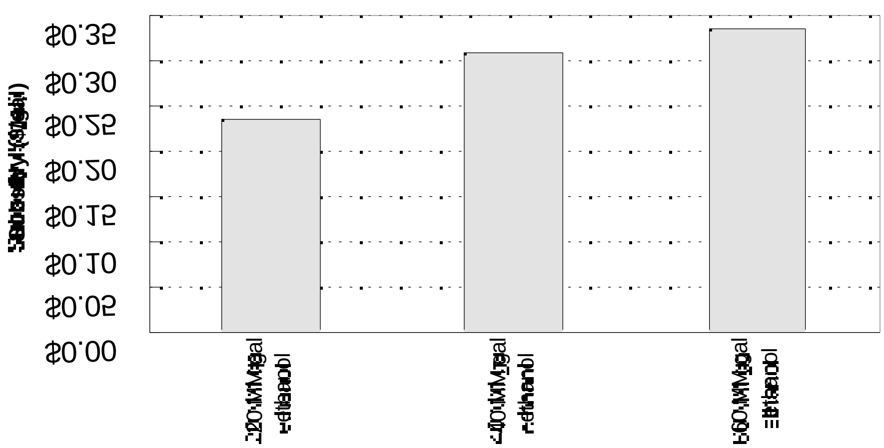

Figure 3-2. Value of subsidy per gallon for ethanol plants using forest material feedstock

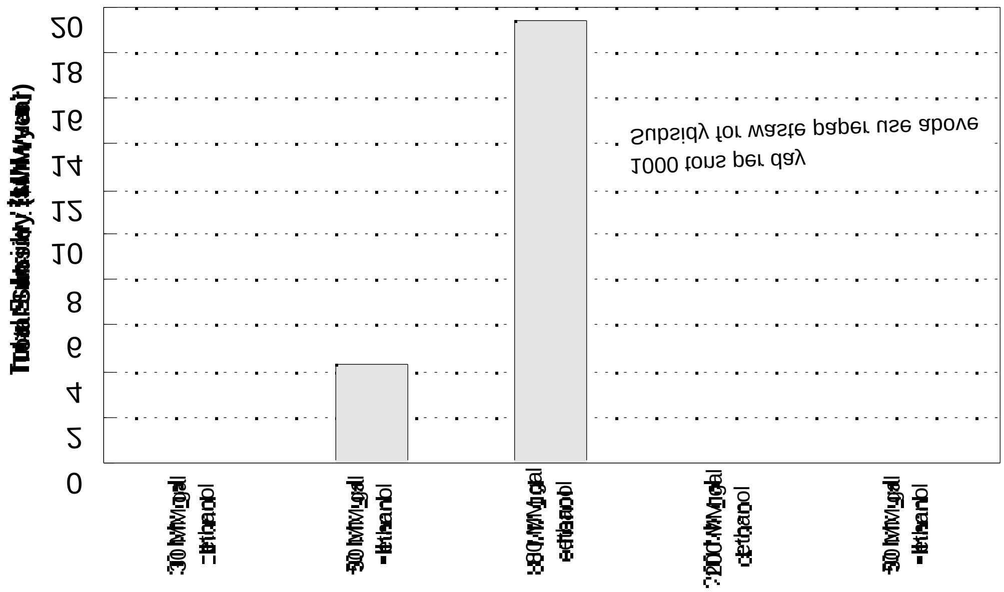

Figure 3-3. Annual subsidy value for ethanol plants using urban waste feedstock

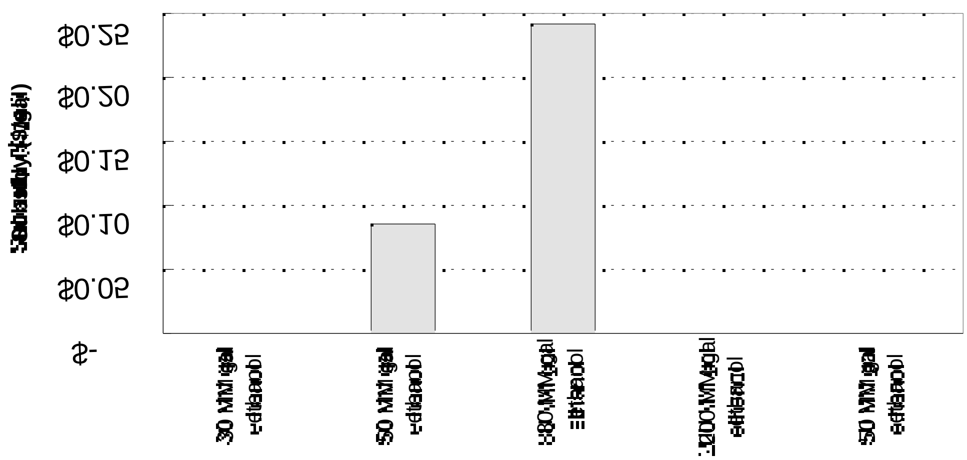

Figure 3-4. Value of subsidy per gallon for ethanol plants using urban waste feedstock

Similarly, urban wood waste is also used as a feedstock for power plants. The cost of urban wood waste fuel has risen to $50/ton in the past when it was in short supply for biomass power plants. The amount of wood waste and tree waste is limited so additional waste material was assumed to come from waste paper.

Currently, most forms of recycled paper are very costly. For example the price of recycled newspaper is about $100/ton. Using waste paper as a feedstock has a potential value for cities or materials recycling facilities (MRF) that must dispose of waste materials in land fills.

A MRF must dispose of waste material and pay approximately $20 in tipping fees and $15 in transportation. Therefore using the material for ethanol production would save a MRF $35 per ton which could be used to process and sort the waste paper. A total cost of $45 per ton was assumed with a net cost of $10 per ton. The largest MRFs have access to about $360 tons/year of waste paper so the $10 per ton price was assumed for only a small to medium size ethanol plant. For larger plants, the waste paper and other feedstocks would need to be shipped from other recycling facilities.

For smaller 30 million gallon per year ethanol facilities located at MSW facilities, transportation costs were assumed to be zero for waste materials. A combined MSW processing and ethanol facility would not likely be located with an existing biomass power plant; therefore, feedstock transport assumptions were assumed to increase for facilities located at biomass power plants.

Table 3-5. Summary of feedstock cost assumptions

Feedstock Category	Composite Cost ($/ton)		Feedstock Materials	Cost ($/ton)
Subsidy Assumption	Yes	No		
Forest Material	14.7	39.0	Forest thinnings Lumbermill waste	43.5 20.0
Agricultural Residue	18.4	25.9	Other Ag. Waste Rice Straw Orchard prunings	13.4 27.9 31.0
Urban Waste	15.4	42.4 (16)	Separated waste paper Yard waste Urban wood waste Tree pruning chips	65.7 (10) 10.2 18.6 13.1
Energy Crops	43.6	43.6	Eucalyptus	43.6

Feedstock costs for mid-term 40 to 50 MM gal/year ethanol capacity. Transportation costs vary with plant size. Larger plant sizes require more feedstock and greater transportation distances. Small urban waste plants can obtain low cost waste paper feedstocks if located with a material recovery facility.

4.0 Transportation costs

Transportation costs were estimated based on costs of truck transport, which include a fixed loading/unloading cost per truckload, and a cost per mile of transport distance. These cost components are shown in Table 4-1.

Table 4-1. Primary components of transportation costs.

Component	Cost
Loading/unloading cost	$45 per truckload[1]
Travel cost	$3.75 per one-way mile per truckload[2]

[1]Based on one hour per truckload at $45/hr truck labor and vehicle cost.
[2]Includes $3/mi truck labor and vehicle cost ($45/hr, 30 round-trip miles per hour average speed) and $0.75/mi fuel cost (4 mi/gal, $1.50/gal).

Feedstocks are assumed to be transported by tractor-trailers with volume capacity of 80 cubic yards and maximum load of 26 tons per truckload. All of the materials studied would exceed the volume limit before reaching the maximum weight load, so dry mass per truckload was calculated for each material based on bulk density and typical moisture content, as shown in Table 4-2.

Table 4-2. Feedstock material dry mass per truckload is a function of bulk density and moisture content

Feedstock	Bulk Density (lb/cu ft)	Mass (tons/ truckload)	Moisture	Dry mass (BD tons/ truckload)
Forest Material				
Forest Slash/Thinnings	20	21.6	30%	15.1
Agricultural Residue				
Other Agricultural Waste	19	20.5	30%	14.4
Rice Straw	13	14.0	31%	9.7
Orchard Prunings	20	21.6	30%	15.1
Urban Waste				
Segregated Waste Paper	20	21.6	5%	20.5
Yard Waste	20	21.6	30%	15.1
Urban Wood Waste	19	20.5	30%	14.4
Landscape/Tree Prunings	19	20.5	30%	14.4
Energy Crops				
Eucalyptus	20	21.6	30%	15.1

Round-trip transport distance was calculated in one of two ways, depending on the material. For materials such as waste paper and yard waste that would be transported to the ethanol plant from a central collection point, a reasonable distance between the collection point and the hypothetical plant location was assumed. For urban waste feedstock materials, this distance increased with increasing plant size to reflect that materials would be trucked from several collection points rather than one nearby collection point.

For materials that would be gathered from an area rather than from a collection point, including forest slash and thinnings, rice straw, and eucalyptus, transport distance was derived by determining the size of the geographic area required to generate the needed quantity of material (using reasonable assumptions about material density and availability). Average one-way transport distance was then calculated from this area.

Ethanol plants using forest material feedstock were assumed to be co-located with a lumbermill, which eliminates transport costs for lumbermill waste. Small (30 MM gal/yr) grass roots ethanol plants using urban waste feedstock were assumed to be co-located with an urban waste collection center to eliminate transport costs. Larger ethanol plants were deemed to be too large to be limited to one collection center.

Tables 4-3 and 4-4 show the calculated transport distances and transport costs, respectively, for each scenario.

Table 4-3. Feedstock material transportation distances

Forest Material	**Timeframe**				
	Near	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Transportation Distance (one-way miles)**				
Lumbermill Waste	0	0	0	0	0
Forest Slash/Thinnings	26	26	42	54	34

Agricultural Residue	**Timeframe**					
	Near	**Mid**	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Transportation Distance (one-way miles)**					
Other Agricultural Waste	20	20	20	20	20	20
Rice Straw	14	14	19	15	23	16
Orchard Prunings	20	20	20	20	20	20

Urban Waste	**Timeframe**						
	Mid	**Mid**	**Mid**	**Mid**	**Long**	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Transportation Distance (one-way miles)**						
Segregated Waste Paper	0/15[1]	19	N/A	25	0/15[1]	25	43
Yard Waste	0/15[1]	19	19	25	0/15[1]	25	43
Urban Wood Waste	0/15[1]	19	19	25	0/15[1]	25	43
Landscape/Tree Prunings	0/15[1]	19	19	25	0/15[1]	25	43

Energy Crops	**Timeframe**		
	Long	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Transportation Distance**		
Eucalyptus	11	19	29

[1]0 miles for grass roots plant, 15 miles for co-located plant.

Table 4-4. Feedstock material transportation costs

Forest Material	**Timeframe**				
	Near	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Transportation Cost ($/BD ton)**				
Lumbermill Waste	0	0	0	0	0
Forest Slash/Thinnings	9.6	9.5	13.5	16.4	11.5

Agricultural Residue	**Timeframe**					
	Near	**Mid**	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Transportation Cost ($/BD ton)**					
Other Agricultural Waste	8.4	8.4	8.4	8.4	8.4	8.4
Rice Straw	9.9	9.9	12.1	10.4	13.7	10.9
Orchard Prunings	8	8	8	8	8	8

Urban Waste	**Timeframe**						
	Mid	**Mid**	**Mid**	**Mid**	**Long**	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Transportation Cost ($/BD ton)**						
Segregated Waste Paper	0/4.9[1]	5.7	N/A	6.8	0/4.9[1]	6.8	10.1
Yard Waste	0/6.7[2]	7.7	7.7	9.2	0/6.7[2]	9.2	13.7
Urban Wood Waste	0/7.1[3]	8.1	8.1	9.7	0/7.1[3]	9.7	14.4
Landscape/Tree Prunings	0/7.1[3]	8.1	8.1	9.7	0/7.1[3]	9.7	14.4

Energy Crops	**Timeframe**		
	Long	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Feedstock Transportation Cost**		
Eucalyptus	5.8	7.6	10.3

[1]$0/BD ton for grass roots plant, $4.9/BD ton for co-located plant.
[2]$0/BD ton for grass roots plant, $6.7/BD ton for co-located plant.
[3]$0/BD ton for grass roots plant, $7.1/BD ton for co-located plant.

The transport costs and distances derived for this study are fairly consistent with those used in previous studies (Tiangco).

5. Resource Constraints

The quantities of available biomass, competing uses, and transportation distances limit affect the cost of feedstocks. The mix of feedstocks for an ethanol plant must be managed to deal with seasonal availability of feedstocks and to avoid price spikes. The following evaluates constraints on the availability of biomass feedstocks.

5.1 Forest Material

The availability of forest material as feedstock at reasonable cost for ethanol production is constrained primarily by transportation costs and access. The amount of forest material needed for even the largest scenario analyzed in this study is a small fraction of the estimated amount available in California. For example, the 60 million gal/yr ethanol plant scenario requires 0.67 million BDT/yr of forest slash and forest thinnings, which is approximately 10 percent of the total amount currently available annually in California (based on current rates of forest thinning, which are presumed to be inadequate). However, transportation costs increase quickly with plant size as the plant must draw thinnings and slash from a larger geographic area, while the amount of available lumbermill waste remains fixed. In addition, collecting costs could increase significantly if acreage with poor road access is needed as a source of thinnings or slash. Figure 5-1 illustrates the potential mix of feedstocks for ethanol production and the lignin available for electric power production.

Another constraint on forest material availability is thinning frequency, which perhaps could be performed more or less frequently than the 10 years assumed in this analysis. In addition, forest slash availability is constrained by the amount of logging operations in the vicinity of the ethanol plant. Lastly, the level of support for forest thinning, translated into a subsidy for thinning operations, could vary over time.

5.2 Agricultural Residue

The estimated mix of agricultural feedstocks is illustrated in Figure 5-2. Alternate uses for agricultural residue affects the availability of some materials as a feedstock for ethanol production. Orchard prunings are a feedstock for biomass power production. Other agricultural materials such as spoiled fruits and vegetables are not suitable as powerplant fuels; however, their availability is seasonal and they tend to rot quickly. Lignin from ethanol production could provide a fuel for biomass powerplants as illustrated in Figure 5-2. This balance of lignin could allow for an efficient utilization of resources where the cellulose is first converted to ethanol.

Rice straw is seasonally available as a feedstock. 1.5 million tons per year are produced in California but not all of this material is harvested. Competing uses include bedding material for livestock. Rice straw contains a high silica content so it is likely that lignin derived from rice straw could not be burned in biomass power plants as separating the silica would be costly. Silica erodes the boiler tubes from power plants.

Insert figure 5-1 HERE -- not available in on line PD version

Insert Figure 5-2 HERE -- not available in on line PDF verion

If rice straw or waste paper were not subsidized, it was assumed that more tree waste and urban wood waste would need to be used as feedstocks for agricultural and urban based plants. The availability of such materials is currently limited which would be an obstacle for the economic production of ethanol. In such a case, more lignin is generated and it may be feasible to maintain the feedstock supply to a biomass power plant while using available woody feedstocks for ethanol production especially if ethanol production could be supplemented with leafy materials and other residues that are not suitable as powerplant fuel. These materials may contain high levels of ash and other contaminants. For example, yard waste may contain over 20 percent ash. Relying on a large quantity of alternative materials for ethanol production may be unrealistic. Given the large quantities of available rice straw, this material appears to be a key feedstock for ethanol plants in the 20 MM gal/year and greater capacity.

5.3 Urban Waste

The availability of urban waste materials at one location affects the these feedstocks. Urban woodwaste is already used as a fuel for biomass power plants. This is a lower grade of waste wood referred to as power plant fuel. Combining urban wood waste, waste paper, and other materials increases the material that would be available for ethanol production as shown in Figure 5-3. An ethanol plant could consume all of the urban wood waste burned by a biomass power plant and all of the waste paper from a MRF. Additional tree waste and yard waste could supplement these feedstocks. For ethanol plants over 30 million gallons per year, additional material would need to be brought from other MRFs or transfer stations. In this case, addtional costs for transportation as well as handling and a premium to incentivize the consistent availability of the feedstock would add to the price of the feedstock. It is not practical to make collection facilities larger and reduce tipping fees as much of the material is delivered in smaller trucks. For example, tree chips are hauled in a truck that may hold only 3 tons of material and a long drive to a large ethanol plant would increase transportation costs.

The amount of waste paper that would be available for a low cost at any one facility is limited to about 360 tons per year for larger facilities. An ethanol plant located with a material recovery facility may be able to obtain waste paper feedstocks in the range of 0 to $10 per ton after clean up costs are taken into account. Larger ethanol plants will likely need to transport feedstocks from other material recovery facilities.

5.4 Energy Crops

The potential use of energy crops is constrained by several factors, which are discussed in Section 4 of the main report. The primary economic constraints include the need for crops that do not require irrigation, and the fact that energy crops must be grown in close proximity to the ethanol plant to keep transport costs reasonable. This depends on having significant land nearby that can be dedicated to energy crops.

In addition, the lack of current usage of energy crops creates significant uncertainty about the costs of energy crops such as eucalyptus.

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5.5 Potential Ethanol Production Capacity

Table 5-1 illustrates the potential ethanol production capacity in the mid-term. If planned ethanol facilities are constructed and expanded in capacity, it appears that 170 million gallons could available in the mid-term. A large scale ethanol industry, producing 520 million gallons per year, could include four pants in for each of the three feedstock categories by the year 2007. This scenario would require a well defined, secure demand for ethanol and could evolve from planned ethanol production facilities. Biomass resources for this scenario appear to be within the amount of material available in the state as well as within transportation constraints and competing demands for the feedstocks. Permitting, secure ethanol demand, and case-by-case feedstock availability would be key constraints that would limit the rapid construction of ethanol plants. A combination of plant capacities could make up the mix of mid-term ethanol supply in California. Plants over 50 million gallons per year would require significant transportation of feedstock material, but production costs could be lower if the cost of feedstock transportation does not rise to quickly.

Table 5-1. Potential Ethanol Production Capacity

Feedstock Supplies			**Large Scale No. Plants**	**Moderate Scale No. Plants**
			4	2
Forest Material	40	MM gal/yr	160	80
Lumbermill Waste	100	M tons/year	400	200
Forest Slash/Thinnings	414	M tons/year	1656	828
			4	1
Agricultural Residue	40	MM gal/yr	160	40
Other Agricultural Waste	114	M tons/year	456	114
Rice Straw	332	M tons/year	1328	332
Orchard Prunings	179	M tons/year	716	179
			4	1
Urban Waste	50	MM gal/yr	200	50
Segregated Paper	526	M tons/year	2104	526
Urban Wood/Tree Waste	201	M tons/year	804	201
Landscape/Tree Prunings	237	M tons/year	948	237
Yard Waste, Wood Fines	101	M tons/year	404	101
			12	4
Total biomass		MM tons/year	8816	2718
Total ethanol		MM gal/yr	520	170

Appendix H

Chapter VII

Ethanol Market: Current Production Capacity, Future Supply Prospects, and Cost Estimates for California

Appendix H

Chapter 7

Update on the Ethanol Market: Current Production Capacity, Future Supply Prospects, and Cost Estimates for California

Prepared For Arcadis Geraghty & Miller
On behalf of the California Energy Commission

Under Subcontract No. JM60090

June 25, 1999

BY:

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Energy Security Analysis, Inc. (ESAI) was retained by Arcadis Geraghty & Miller on behalf of the California Energy Commission (CEC) to provide an update of ESAI's previous work regarding the availability and cost of fuel ethanol for the California market.

The following text is a summary of the assumptions, methodology and conclusions of this update. In general, the assumptions and methodology are the same as those used by ESAI in estimating ethanol costs in the CEC's November 1998 report, *Evaluating the Cost and Supply of Alternatives to MTBE in California's Reformulated Gasoline.* New data and some minor modifications were used to provide the updated cost estimates as set forth in this report. Further details regarding calculations and methodology can be found in the accompanying appendices. This report analyzes two scenarios, with two different time periods: intermediate term and long term. As in the previous CEC report, the intermediate term assumes no new capital additions to capacity are made. The long term assumes that unlimited capital additions to capacity are possible.

The first scenario assumes that MTBE is banned in California. Ethanol must be imported from out of state (very little ethanol is currently produced in state). The second scenario posits that MTBE is banned throughout the U.S.

The intermediate term supply curve for ethanol delivered to California under a California only ban is constructed by estimating the price at which ethanol supplies in the Midwest and other states can be bid away from gasoline blenders in those regions. Linear equations are used to estimate these breakeven prices, with an assumption of a baseline gasoline price of 62 cents/gallon and an MTBE price of 85 cents/gallon. The latest available state-by-state gasoline price data was used to determine relative state prices with reference to the 62 cents/gallon baseline price. The breakeven price at which each state values ethanol was then matched with the corresponding volume of ethanol used by each state. State ethanol usage was estimated by extrapolating the latest Federal Highway Statistics on ethanol use (1997 data) with the latest state by state gasoline usage data (Energy Information Agency 1998 data). Thus, in this report, relative state gasoline prices and ethanol volumes are different than in the previous CEC report. In addition, the most current state tax data and ethanol tax incentives are incorporated into this analysis. Illinois and Wisconsin are assumed to value ethanol as an oxygenate for RFG use in this report. As in the previous CEC report, unused U.S. capacity as well as ethanol imported through the Caribbean was considered in the supply curve.

The result is a slightly steeper supply curve than in the previous report. The first 10,000 b/d of ethanol can be delivered to California (assuming 15 cent/gallon transportation cost) at approximately 82 cents/gallon, ex-tax incentive ($1.36/gallon selling price). Up to 50,000 b/d would cost approximately 92 cents/gallon ex-tax incentive ($1.46/gallon selling price). And up to 100,000 b/d delivered to California would cost 113 cents/gallon ex-tax incentive ($1.67/gallon selling price).

Longer term ethanol prices can be expected to moderate to the marginal cost of production. However, this ethanol production cost will increase as more corn is used to produce ethanol (increasing the price of corn) and as the by-products (such as distiller dried grains, gluten meal and gluten feed) drop in value due to their increased supply. As in the previous CEC report, a notional production cost was estimated using various assumptions regarding baseline corn costs and by-product costs. Corn elasticity values were corrected in this report relative to the previous CEC report, which increased the rate at which corn prices increase with added ethanol usage.

The result is a cost curve which delivers ethanol to California at 69 cents/gallon ex-tax incentive ($1.23/gallon selling price) for the first 10,000 b/d, 75 cents/gallon ex-tax incentive ($1.29/gallon selling price) for up to 50,000 b/d, and 83 cents/gallon ex-tax incentive ($1.37/gallon selling price) for up to 100,000 b/d.

If MTBE is banned throughout the U.S., the resulting intermediate term cost curves for ethanol delivered to California will be correspondingly higher. Assuming the oxygenate mandate remains on the books, blenders outside California would compete with California blenders for the existing ethanol supply. All ethanol in the U.S. would be valued as an oxygenate instead of as a lower value blending component for gasohol.

The resulting intermediate term cost curve delivers ethanol to California at $1.11/gallon ex-tax incentive ($1.65/gallon selling price) for the first 10,000 b/d, $1.14/gallon ex-tax incentive ($1.68/gallon selling price) for up to 50,000 b/d, and $1.16/gallon ex-tax incentive ($1.70 selling price) for up to 100,000 b/d. It should be noted that this intermediate term cost curve assumes that blenders outside California have access to the alternative oxygenates TAME and TBA. If they must use ethanol as well, then there will be a substantial imbalance between demand and supply for ethanol. The resulting bidding war for the limited supply of ethanol cannot be modeled.

The long term cost curve for ethanol delivered to California under a U.S. MTBE ban is slightly higher than the long term curve with a California only ban of MTBE, by about 2 cents/gallon per 10,000 b/d increment.

SectionA-1 -- Detailed descriptions of intermediate and long term cost estimates for ethanol.

A-1.0: Ethanol availability in the U.S.

Currently, the U.S. produces about 100,000 b/d of fuel ethanol on an average annual basis, and imports relatively small volumes from Central America. On-line capacity in the U.S. equals 115,000 b/d. Therefore, the U.S. fuel ethanol industry is now operating at roughly 85 percent of capacity on an annual basis. Demand is calculated at approximately 89,000 b/d and there is about 26,000 b/d of spare capacity that could be used to supply California. This spare capacity is generally concentrated among the major producers of ethanol. While there are several ethanol plants that have shut down over the years, and might be counted as capacity that could come online to meet Californian demand, we can assume that these plants are not *currently* operating because they are not competitive. If they were competitive they would be producing at the recent market prices for ethanol ($1.00/gallon to $1.20/gallon)

A-2.0: Scenario One: MTBE Banned in California

The first scenario presumes that MTBE is eliminated in California, but that it remains a viable oxygenate for blending in other states.

A-2.1: Intermediate term ethanol supply curve estimates

The price/volume relationships analyzed below are found in Section I, Table I-1. It is assumed that all subsidies including tax credits for blenders are in place throughout the country.

There are several blocks of ethanol supply that are available to California in the intermediate term. First, California already consumes some ethanol. Second, there is a small volume of ethanol that can be imported from the Caribbean duty free that will be available. Third, there is unused capacity (see above). Finally, there is a finite volume of ethanol that is consumed by states with RFG programs and winter oxygenate programs, and ethanol that is blended for gasohol in the Midwest states.

According to data compiled by the Federal Highway Administration, California consumed roughly 8,800 b/d of ethanol on average in 1997. This is the baseline volume of ethanol available to California; it can be presumed to be available at the Los Angeles/San Francisco wholesale average price for ethanol in 1997 of $1.24/gallon.

Ethanol is blended in gasoline (primarily in the Midwest or Padd II region) where it is more economical to use than MTBE or can be blended with regular or subgrade unleaded gasoline to make a midgrade or premium gasoline.

In the intermediate term (i.e., before substantial new ethanol capacity could be built and substantial quantities of ethanol supplied to the market), California CARB RFG blenders would have to outbid these other users of ethanol in order to secure ethanol supply and comply with Federal oxygen regulations. In other words, the price of ethanol will have to increase to the point where it is cheaper for ethanol blenders outside of California to switch to MTBE for their oxygenate use, or cheaper to buy 100 percent petroleum-based gasoline instead of using ethanol in a mix with regular unleaded gasoline (gasohol).

In order to make these comparisons, ethanol needs to be valued correctly. Ethanol's value to gasoline blenders will first depend on whether it is being used as an oxygenate in oxygenated gasoline or RFG gasoline, or whether it is being used in gasohol as a gasoline extender.

If used as an oxygenate, ethanol's value will depend on the cost of MTBE, the cost of octane and Reid Vapor Pressure (RVP). Using a 2.7 weight % oxygen level in oxygenated gasoline, ethanol's value can be expressed using the following equation[1]:

$$P_{EOH} = (0.852\ P_{B\text{-}MTBE} - 0.923\ P_{B\text{-}EOH} + 0.148\ P_{MTBE} - C_{EOH})/0.077$$

Where

P_{EOH} = Price of ethanol
$P_{B\text{-}MTBE}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with MTBE.
$P_{B\text{-}EOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with ethanol
P_{MTBE} = Price of MTBE
C_{EOH} = Any costs associated with blending ethanol

If used as a gasoline extender, ethanol's value will depend on the retail price of gasoline, the rack price of gasoline, and the cost of octane. Using the typical 10 percent blend of ethanol found in most gasohol, ethanol's value can be expressed using the following equation:

$$P_{EOH} = -\ (\ P_{R\text{-}MOGAS} - P_{MOGAS} - P_{R\text{-}GASOHOL} + 0.9\ P_{B\text{-}EOH} + C_{EOH}\ )\ /\ 0.1$$

Where

P_{EOH} = Price of ethanol
$P_{R\text{-}MOGAS}$ = Retail (pump) price of pool gasoline
P_{MOGAS} = Rack price of pool gasoline
$P_{R\text{-}GASOHOL}$ = Retail (pump) price of gasohol
$P_{B\text{-}EOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with ethanol
C_{EOH} = Cost associated with blending ethanol

[1] The derivations of this formula (EOH valued as an oxygenate) and the following formula (EOH valued as gasohol), provided by MathPro, Inc., can be found in Section B.

In order to determine the price/volume relationships, blocks of supply are identified on a state-by-state basis, using the most recently available data. Ethanol volumes consumed in each state were estimated using 1997 ethanol usage data from the October 1998 Federal Highway Administration report "Estimated Use of Gasohol" and applying this data to more recent 1998 gasoline sales data supplied by the early edition of the 1999 Energy Information Agency *Petroleum Marketing Annual*. Breakeven ethanol values (using the above linear equations) were then determined to determine the price at which these volumes would be bid away from their existing markets.

Since gasoline prices differ in each state, ethanol is valued differently according to its market. Retail and rack gasoline price data from the U.S. Energy Information Agency's *Petroleum Marketing Annual* publication were used to determine gasoline prices for all states that consume ethanol. Prices were adjusted for use in this study by basing them on a base of 62 cents/gallon pool gasoline rack price and a $1.00/gallon retail price and then adding a differential based on the relative prices found in each state. For example, Pennsylvania's rack price for gasoline was 1.3 cents/gallon higher than that of Louisiana, which had the lowest U.S. rack price; therefore, for the purposes of this study, the rack price for Pennsylvania is 63.3 (62 plus 1.3). See SectionC for a ranking of state-by-state rack and retail gasoline prices.

Using the formulas expressed above, ethanol values were determined for each state. Arizona, Nevada, Washington, California, New Mexico and Colorado use ethanol primarily for winter oxygenate blending instead of as gasohol blendstock (thus the higher value for ethanol). In addition, the RFG markets of Milwaukee, Wisconsin and Chicago, Illinois primarily use ethanol as the required oxygenate (approximately 95 percent in both cases).

Several states, notably Connecticut, Idaho, Illinois, Ohio, Iowa, and South Dakota, have state incentives for ethanol use, in the form of an income tax exemption. The presence of such state subsidies increases the price at which ethanol will be bid away from these states, by 10 cents per gallon of ethanol for Connecticut, Ohio and Iowa, 10 cents for Illinois (estimated using the 2% sales exemption on a 6.25% sales tax), and 21 cents for South Dakota.

The estimated volume of ethanol sales (b/d) and calculated ethanol values (cents/gallon) for each state are listed in Table A-1 below:

Table A- 1

U.S. Ethanol Usage and Blending Values						
State	EOH value	EOH usage (b/d)		State	EOH value	EOH usage (b/d)
Louisiana	65.9	59		Kentucky	70.0	451
Pennsylvania	67.2	4,300		Missouri	70.4	443
New York	67.2	1,498		New Jersey	72.8	894
Alabama	67.7	274		Connecticut	77.0	244
N. Dakota	67.7	340		Ohio	77.2	10,955
North Carolina	67.8	2,379		Iowa	80.8	3,967
Texas	67.8	3,547		Illinois RFG market	87.8	1,300
Virginia	68.2	2,325		Alaska	88.5	487
Michigan	68.2	1,895		S. Dakota	89.4	1,124
Indiana	68.6	4,605		Illinois	100.9	11,698
Maryland	68.6	187		Washington	101.7	221
Tennessee	68.6	23		Wyoming	101.9	9
West Virginia	68.9	9		Arizona	103.0	1,603
Nebraska	69.1	1,354		Wisconsin	104.1	4,747
Florida	69.5	105		New Mexico	104.5	920
Kansas	69.8	225		Colorado	104.8	4,541
Note: EOH values assume lowest state gasoline rack price at 62 cents/gallon; MTBE price is assumed to be 85 cents/gallon. Other assumptions can be found in SectionB.						

In the supply curve constructed from the above data, the block representing ethanol consumed in Minnesota is excluded from the volume that can be bid away to California blenders. Minnesota has a year-round oxygenate mandate stipulating a 2.7% minimum oxygen content in all gasoline sold in the state. According to industry sources, the language in this regulation precludes the use of MTBE, and as such, the mandate amounts to an ethanol mandate. Thus, there is approximately 13,000 b/d of ethanol consumed in Minnesota that cannot be bid away.

There are two other blocks of supply that need to be considered. These are volumes of ethanol imported from the Caribbean and ethanol that could be supplied by increasing U.S. utilization capacity to 100 percent.

U.S. law (the Caribbean Basin Initiative, or CBI) states that the equivalent volume of up to seven percent of U.S. ethanol production can be imported duty-free into the United States. Historically, this has been essentially unfinished ethanol from beer still/wine alcohol that is exported from the European Union, and sent to countries like Jamaica and El Salvador, where it is upgraded and sent to the U.S. Industry sources report that the ethanol is priced at approximately 60 cents/gallon, and that freight and insurance would bring the delivered price to California to almost 83 cents/gallon. With an assumed production of 115,000 b/d in the U.S., the Caribbean ethanol volume available is estimated at almost 9,000 b/d.

Since U.S. ethanol capacity is 115,000 b/d and the average annual consumption is 89,000 b/d, there is approximately 26,000 b/d of surplus ethanol that can be supplied to California. Because individual ethanol plant data is not available, and each plant runs on different economics, it is not possible to determine what price for ethanol would cause each plant in the U.S. to reach 100 percent of capacity.

However, it is possible to create a notional ethanol producer's margin, and compare this to historical utilization capacity. The margin for an ethanol producer is equal to the price received for ethanol and other corn by-products (such as distiller's grains and starches) minus the cost of producing ethanol (composed mostly of corn feedstock costs). Historical price data for ethanol, corn, dried distiller grains, gluten meal and gluten feed were obtained from Hart's Publications' *Oxy Fuel News.* Typical variable and fixed cost information for both wet and dry milling ethanol producers (See Section D) were also obtained from ethanol producers. A notional margin for both wet and dry milling producers was calculated on a monthly basis for the last six years, and compared to production data from the Energy Information Agency (see Section E). According to this data, it appears that the only time that utilization rates in the U.S. reached near 100% (winter 94-95), the notional margin (averaged for both wet and dry milling producers) was approximately 40 cents/gallon.

The historical average net production cost (a weighted average for both wet and dry milling producers), according to the data used in this report, has been approximately $1.03/gallon over the past six years. Therefore, the price required to bring U.S. production to full capacity is equal to the $1.03/gallon net production cost plus 40 cents/gallon margin, or $1.43/gallon. Net of the 54 cent/gallon subsidy, this equals 89 cents/gallon.

With approximately 67,000 b/d of ethanol bid away from other states, 9,000 b/d available through the Caribbean, as well as 26,000 b/d available by boosting production, a supply curve can be constructed up to demand levels of 111,000 b/d. This is the approximate demand level that would be necessary for California if ethanol were granted a 1 psi RVP waiver, effectively allowing blenders to use up to 3.5 weight % oxygen level in CARB gasoline.

MTBE demand will fall to zero in California as a result of a ban on its use. Ordinarily this would result in a severe drop in MTBE's price, and perhaps a knock-on effect in the price of other oxygenates. However, blenders outside of California that use ethanol will need to replace oxygen or octane if ethanol is bid away; and they will most likely use MTBE. Since end-users of ethanol and MTBE will in essence be swapping demand for oxygenates, there should not be any net change in price for MTBE.

In summary, the intermediate term supply curve for ethanol delivered to California is constructed by determining the correct ethanol value in each state that consumes the fuel, and assuming that the amount consumed by each state will be bid away by Californian end-users once the price has risen to breakeven levels above which the original consumers would find it too expensive. Minnesota ethanol is not considered, and in addition there is 9,000 b/d of ethanol that is available through the Caribbean, as well as 26,000 b/d of ethanol that is available by increasing producers' utilization rates to 100%.

A-2.2: Long Term Ethanol Cost Estimates

Within 2-3 years, added California ethanol demand would lead to an expansion of ethanol capacity in the U.S. Furthermore, the increased demand for ethanol would justify the construction of nearly 30,000 b/d of capacity in the U.S. that has already been planned or proposed (see Section H, Table H-3, for a listing of plants proposed to come on-line). In addition to the projects already planned, new producers will enter the market, attracted by higher intermediate term prices and increased demand caused by a switch to ethanol consumption in California.

The long term scenario assumes that in addition to the approximately 82,000 b/d of ethanol already consumed in the U.S. outside of California, additional ethanol supply would be produced to supply California's needs. Assuming that approximately 91% of ethanol will continue to be processed with corn feedstock, and that approximately 2.6 gallons of ethanol are produced from a bushel of corn, this increased demand will require additional feedstocks of up to 590 million bushels of corn if 100,000 b/d of ethanol were delivered to California in addition to the current demand levels outside California.

In a long term time period, the additional required volumes of corn feedstock will be supplied in response to higher demand and higher corn prices in the intermediate term. Additional corn production is expected to respond to the long term supply elasticity of price for corn (the percentage change in corn supply divided by the percentage change in corn price). The U.S. Department of Agriculture (USDA) has generally used the value of 0.3 as an estimate for this value. This roughly works out to a 5-8 cent/bushel increase in price for every additional 100 million bushels of corn utilized for ethanol production. Using this elasticity value, it was possible to calculate the increasing price for corn at various volumes additional ethanol supplied to the market. Increasing corn costs will tend to increase the net production cost for ethanol production. For the purposes of this study, a baseline of $2.60/bushel was used. With additional ethanol demand (above current capacity) of 50,000 b/d, corn costs are expected to rise to $2.85/bushel. See Section G for detailed calculations.

It is also expected that as a result of the additional processing of corn for ethanol production, there will be a large increase in the supply of by-products, such as distillers' dried grains (DDG), corn gluten feed, corn gluten meal and corn germ. As additional volumes of these products are place on the market, it is expected that the price of these by-products will decline. Previous USDA studies have reported that an increase in ethanol production of 4.8 billion gallons would decrease corn gluten meal prices by 7 percent, corn gluten feed prices by 12.3 percent, and distillers' dried grains by 4 percent.[2]

Using this data, long term elasticity values were calculated for each by-product of ethanol production. These elasticities were then used to determine the price of DDG, corn gluten feed, corn gluten meal, and corn germ at various volumes of ethanol supplied to the market in the long term. See Section G for detailed calculations.

By determining the long term price of corn and the long term price of ethanol by-products, long term net production costs were calculated for various volumes of ethanol. All other fixed and variable costs besides corn cost and by-product prices were held constant.

In the long term scenario, ethanol prices are expected to decline to their marginal cost of production as calculated above. Since most production will still be located in the large corn-producing states, the transportation cost of 15 cents/gallon is held constant. Long term ethanol prices will be lower than intermediate term prices, but will still be upward sloping due to increasing net production costs (as a result of increasing corn costs and lower co-product revenue).

The price/volume relationships analyzed below are found in Section I, Table I-2. It is assumed that all subsidies including tax credits for blenders are in place throughout the country.

A-3.0: Scenario Two: MTBE Banned in U.S.

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[2] House, R., M. Peters, H. Baumes, and W.T. Disney "Ethanol and Agriculture: Effect of Increased Production on Crop and Livestock Sectors," USDA, Economic Research Service. Agricultural Economic Report Number 667. May, 1993.

The second scenario in this study posits that MTBE is banned not only in the state of California, but nation-wide. This will clearly boost the cost of ethanol delivered to California higher than the California-only ban scenario.

If MTBE were banned throughout the U.S., Federal RFG and winter oxygenated gasoline programs would need to switch to ethanol to replace MTBE, assuming the Federal oxygen requirement remained on the books. Of course, on an oxygen basis, ethanol barrels would not need to replace MTBE barrels one for one, as ethanol contains roughly twice the amount of oxygen as MTBE.

Besides the extra capacity existing in the U.S., there is little ethanol elsewhere that can be imported.

Brazil is the largest producer of ethanol in the world, and has a capacity of about 260,000 b/d. However, the U.S. would be unable, under present circumstances, to import much ethanol from Brazil. Brazil has mandated that all gasoline sold in the country contain 24% ethanol. Brazil's average gasoline consumption is about 300,000 b/d, and therefore the amount of mandated ethanol use is 66,000 b/d. In addition, however, 4 million of Brazilian cars are built to run on 100% ethanol (hydrous ethanol). The ethanol used to fuel these cars must therefore be considered dedicated ethanol, or ethanol that cannot be pulled from Brazil for use outside the country. This amounts to about 148,000 b/d of dedicated ethanol supply.

Therefore, in reality, there is very little Brazilian ethanol that can be supplied to the U.S. market, since 214,000 b/d (148,000 b/d + 66,000 b/d) is currently dedicated or mandated for use in Brazil. During the immediate term, at most about 30,000 b/d of surplus ethanol could presently be supplied to the U.S. market as surplus Brazilian ethanol. While the number of cars running on 100% ethanol in Brazil is declining, overall gasoline consumption has been rising very rapidly, approaching close to 10% growth in 1997 and 6% growth in 1998. Therefore, lower ethanol use in Brazil by dedicated vehicles is being offset to a large degree by the growth of the gasoline pool. In addition, foreign ethanol that is not considered under the Caribbean Basin Initiative exemption is currently subject to a 54 cent/gallon tariff. This tariff is presumed to remain in place for the purposes of this study.

France, Italy, and Spain together produce about 30,000 b/d of excess wine ethanol from their combined wine industries. This ethanol, however, would also be subject to the tariff of $.54/gallon applied against foreign produced biomass ethanol. So would other beverage grade ethanol, available in Asia and the FSU.

There are also quantities of synthetic ethanol available on the world market. However, this ethanol would not be eligible for the tax credit, as it is not a biomass fuel, and would need to be diverted from its end use as chemical feedstock.

A-3.1: Ethanol Cost Estimates, Intermediate Term, U.S. Ban on MTBE

The U.S. consumes on an annual basis approximately 2.8 million b/d of reformulated gasoline, and approximately 280,000 b/d of oxygenated gasoline for wintertime carbon monoxide programs. Excluding California, which in the intermediate term is assumed to demand 965,000 b/d of reformulated gasoline in this study, the U.S. consumes 1.84 million b/d of RFG. Excluding Minnesota, which consumes 130,000 b/d of oxygenated gasoline due to its year-round 2.7 weight % oxygen requirement, the U.S. consumes approximately 150,000 b/d of oxygenated wintertime gasoline. Thus, in the event of a U.S. ban on MTBE, the U.S., excluding California and Minnesota, would need to find enough oxygen to satisfy about 1.99 million b/d of gasoline that needs to be either oxygenated for reformulation purposes or for wintertime oxygen purposes.

In the event of a U.S.-wide ban of MTBE, gasoline blenders outside of California will see ethanol as a substitute for MTBE. Therefore, in the intermediate term, California will need to compete for this limited ethanol supply with these outside blenders.

As ethanol is bid above its breakeven value, outside blenders will seek other substitutes, such as TAME and TBA. Presumably, MTBE capacity could be converted to TBA output in order to supply this demand. It is assumed that TAME and TBA are not banned along with MTBE, although this is a possibility, especially for TAME which is an ether with chemical properties similar to MTBE. If TAME and TBA are not available, a different supply curve would result. This is discussed at the end of this section.

In order to make these breakeven comparisons, ethanol needs to be valued correctly. In the previous section assessing the cost of ethanol delivered to California in the intermediate term under a California only ban of MTBE, breakeven values were calculated for blenders of ethanol within each state. Ethanol's value depended on whether it was being used as an oxygenate in oxygenated gasoline in that state, or whether it was being blended in gasohol as a gasoline extender.

In this section, a similar calculation is made. Instead of determining breakeven values needed to bid ethanol away from ethanol blenders in each state, breakeven values are calculated to determine the price necessary to outbid non-Californian blenders of RFG and oxygenated wintertime gasoline. In the case of a U.S. ban on MTBE, gasoline blenders outside California will be seeking alternate oxygenates in the marketplace to satisfy their oxygen blending requirements. These blenders will value ethanol as an oxygenate, and will bid ethanol prices above the typical Midwest gasohol value. Therefore, in order to secure delivery of ethanol to California, blenders in California will need to bid ethanol above the breakeven oxygenate value for each outside blender of RFG or wintertime oxygenated gasoline.

In the intermediate term case scenario with MTBE banned in California only, ethanol's value outside California as an oxygenate depended on the cost of MTBE, the cost of octane and Reid Vapor Pressure (RVP). In this case, however, MTBE has been banned in the U.S., eliminating it as a useful benchmark against which to price ethanol. Ethanol's value will be determined, therefore, by other substitutable oxygenates, such as TAME and TBA.

The value of TAME and TBA can be assumed to be equal to MTBE's market value (85.4 cents/gallon in this study), minus an adjustment for octane differences. Using an octane price of 0.7 cents/octane number, TAME is worth 3.5 cents/gallon less than MTBE (MTBE's octane level of 110 minus TAME's octane level of 105 multiplied by the octane price). TBA is worth 7 cents/gallon less than MTBE (MTBE's octane level of 110 minus TBA's octane level of 100 multiplied by the octane price). TAME's market value is therefore calculated as 81.9 cents/gallon, and TBA's value is calculated as 78.4 cents/gallon. In addition, a 4 cent/gallon differential was added to the TBA/TAME price in Padds I, II, IV, and V to account for similar differentials from Gulf Coast prices that exist today in the MTBE market.

With a benchmark value against which to value ethanol (the averaged price of TAME and TBA), breakeven prices can be calculated by RFG or oxygenated gasoline areas around the U.S.

To determine the breakeven level for ethanol in states requiring RFG gasoline the following equation is used, with the co-efficients set up to account for the volumes of ethanol and TBA/TAME required to achieve a 2.0 weight % oxygen level[3]:

$$P_{EOH} = (0.894\ P_{B\text{-}TAME/TBA} - 0.943\ P_{B\text{-}EOH} + 0.106\ P_{TAME/TBA} - C_{EOH})/0.057$$

Where

P_{EOH} = Price of ethanol
$P_{B\text{-}TAME/TBA}$ = Averaged price of reformulated blendstock for oxygenate blending (RBOB) with TAME and TBA.
$P_{B\text{-}EOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with ethanol
$P_{TAME/TBA}$ = Averaged price of TAME and TBA
C_{EOH} = Any costs associated with blending ethanol

In states where oxygen is needed for blending in wintertime oxygenated gasoline, a similar equation is used, with the co-efficients set up to account for the volumes of ethanol and TBA/TAME required to achieve a 2.7 weight % oxygen level:

$$P_{EOH} = (0.858\ P_{B\text{-}TAME/TBA} - 0.923\ P_{B\text{-}EOH} + 0.143\ P_{TAME/TBA} - C_{EOH})/0.077$$

The price of the RBOBs used in the above equations is dependent on the price of pool gasoline (see Section B for derivation). Since gasoline prices differ in each state, ethanol will be valued differently according to its gasoline market. Rack gasoline price data from the U.S. Energy Information Agency's 1998 *Petroleum Marketing Annual* publication were used to determine gasoline prices for all states that consume reformulated or

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[3] This equation is similar to the equation used in Section 4.1.3.1, which is derived in Section B. In this equation and the one following it, the co-efficients for TBA/TAME is an average of the volumes required to blend TBA and TAME to a 2.0 weight % oxygen level, or a 2.7 weight % level.

oxygenated gasoline. Prices were adjusted for use in this study by basing them on the price of pool gasoline used in the study (62 cents/gallon) and then adding a differential based on the relative prices found in each state. For example, Pennsylvania's rack price for gasoline was 1.3 cents/gallon higher than that of Louisiana, which had the lowest U.S. rack price; therefore, for the purposes of this study, the rack price for Pennsylvania is 63.3 (62 plus 1.3). See Section C for a ranking of state-by-state rack and retail gasoline prices.

Using the formulas expressed above, breakeven ethanol values were determined for each state that blends oxygen for RFG or oxygenated gasoline. The state-level incentives for ethanol use that exists in several states does not effect the breakeven ethanol values here, since the oxygenate breakeven values rise above the gasohol break even values, even with the additional incentives factored in.

Using historical data for RFG and oxygenated gasoline sales in each state (source: U.S. Energy Information Agency 1998 *Petroleum Marketing Annual*), it is possible to determine the volume of ethanol that would be required to satisfy each state's oxygen requirement. Volumes of reformulated gasoline were multiplied by 5.7% to calculate potential ethanol volumes demanded for RFG gasoline at 2.0 weight % oxygen level. Volumes of oxygenated gasoline were multiplied by 7.7 % to calculate potential ethanol volumes demanded for oxygenated gasoline at 2.7 weight % oxygen level.

The potential ethanol volumes (b/d) demanded by each state that requires RFG or oxygenated gasoline and price (cents/gallon) at which ethanol would be valued in each state are listed in Table A-2 below:

Table A- 2

Potential Ethanol Demand by State, and State Ethanol Values				
State	RFG Demand	Oxy Gasoline Demand	Potential Ethanol Demand	Ethanol Value
New Mexico		6,524	502	95.3
Texas RFG	293,845		16,749.18	95.7
Arizona RFG	69,326		3,952	97.1
Montana		595	46	97.1
Utah		2,131	164	98.4
Connecticut	90,619		5,165	98.8
Massachusetts	165,931		9,458	98.8
New Jersey	271,431		15,472	99.2
Maine	31,264		1,782	99.2
New Hampshire	24,040		1,370	99.6
Rhode Island	33,950		1,935	99.8
Nevada		16,688	1,285	99.8
Texas oxy		8,307	639	100.0
Washington		36,919	2,843	100.1
Maryland	115,574		6,588	100.2
Illinois	175,438		10,000	100.6
New York	196,338		11,191	100.7
Wisconsin	46,819		2,669	100.8
Kentucky	32,160		1,833	101.1
Delaware	25,924		1,478	101.1
Oregon		23,636	1,820	101.3
Arizona oxy		23,088	1,778	101.3
Pennsylvania	87,119		4,966	101.9
Indiana	29,983		1,709	102.1
Virginia	136,074		7,756	102.4
Colorado		30,329	2,335	103.0

The supply curve for ethanol delivered to California under a U.S.-wide ban of MTBE is built up by using the above volumes, which represent the amount of ethanol that blenders outside California would potentially demand unless the price was bid above a level at which they value ethanol.

Even if 100,000 b/d of ethanol was bid away from the rest of the country by California (in the case of the entire state blending to a 3.5 weight % oxygen level), the rest of the U.S. could satisfy its oxygen requirements by a combination of leftover ethanol capacity, TAME, TBA, and additions to ethanol capacity.

U.S. RFG demand excluding California is estimated at about 1.84 million b/d. U.S. oxygenated gasoline demand excluding Minnesota is estimated at about 150,000 b/d. With up to 100,000 b/d of ethanol delivered to California, this would leave 15,000 b/d of spare capacity plus 9,000 b/d of ethanol imported from the Caribbean, for a total of about 24,000 b/d. This would account for approximately 421,000 b/d of RFG gasoline demand at 2.0 weight % oxygen level (5.7% ethanol). Total world TAME capacity of nearly 47,000 b/d would account for approximately 378,000 b/d of RFG demand at 2.0 weight % oxygen level (12.4% TAME). And total world TBA capacity of nearly 60,000 b/d would account for approximately 677,000 b/d of RFG demand at 2.0 weight % oxygen level (8.8% TBA). Total RFG demand satisfied by these remaining oxygenates equals 1.48 million b/d, leaving 360,000 b/d of US RFG demand. In addition U.S. oxygenated gasoline demand (150,000 b/d) remains unsatisfied.

The remaining RFG demand of 360,000 b/d would require 21,000 b/d of ethanol at 2.0 weight % oxygen level, while oxygenated gasoline demand of 150,000 b/d would require 12,000 b/d of ethanol at 2.7 weight % oxygen level. It is assumed that this 33,000 b/d of ethanol capacity required to satisfy the remainder of U.S. oxygen requirements could be supplied by increasing yields of fuel ethanol at existing plants (ethanol plants have some flexibility to increase the amount of ethanol they produce at the expense of other outputs). The larger ethanol producers would most likely be the best candidates for this type of expansion, and would add to capacity as the price of ethanol increased, according to the supply curve.

If TAME and TBA are not available to satisfy the rest of U.S. RFG and oxygenated gasoline requirements, then the supply curve will be bounded. U.S. RFG demand excluding California is estimated at about 1.84 million b/d. At 2.0 weight % oxygen content or 5.7% ethanol volume, this equates to about 105,000 b/d of ethanol. U.S. oxygenated gasoline demand is approximately 280,000 b/d. At 2.7 weight % oxygen content or 7.7% ethanol volume, this equates to about 22,000 b/d of ethanol. This total demand of 127,000 b/d of ethanol clearly exceeds U.S. production capacity. California would have to enter a bidding war with other states for the existing supply. There is no way to model the upward spiral in price that would result from a situation of such unbalanced supply and demand in the intermediate term.

The price/volume relationships analyzed below are found in Section I, Table I-3. It is assumed that all subsidies including tax credits for blenders are in place throughout the country.

A-3.2: Ethanol Cost Estimates, Long Term, U.S. Ban on MTBE

The methodology for determining the long term supply curve for ethanol under the U.S.-wide MTBE ban is similar to the case of the long term supply curve under a California-only ban, as explained above. In addition to the ethanol projects already planned, new producers will enter the market in the long term, attracted by higher prices for ethanol in the intermediate term and increased demand caused by a switch to ethanol consumption in California and the U.S. during the intermediate term.

The long term scenario assumes that the entire country uses ethanol in addition to the additional volumes that would be produced to supply California's needs. Assuming that approximately 91% of ethanol will continue to be processed with corn feedstock, and that approximately 2.6 gallons of ethanol are produced from a bushel of corn, this increased demand will require additional feedstocks of up to 767 million bushels of corn per year for California demand of 100,000 b/d in addition to U.S. demand of 127,000 b/d.

In a long term time period, this additional corn can be expected to be supplied in response to demand. Additional corn production is expected to respond to the long term supply elasticity of price for corn (the percentage change in corn supply divided by the percentage change in price of corn), as explained previously in Section A-2.2. Using this elasticity value of 0.3, prices for corn were calculated at various volumes of ethanol supplied to the market. For the purposes of this study, a baseline of $2.60/bushel was used.

As explained in the California-only MTBE ban scenario, additional ethanol production is expected to result in a large increase in the supply of by-products, such as distiller's dried grains (DDG), gluten feed and gluten meal. It expected that the price of these by-products will decline as their supply increases as more corn is processed to produce ethanol. The same byproduct elasticities used in Section A-2.2, are used in this section.

Using the elasticities for the by-products of ethanol production, prices were determined for DDG, gluten feed, and gluten meal at various volumes of ethanol supplied to the market in the long term.

By determining the long term price of corn and the long term price of ethanol by-products, net production costs are calculated at various volumes of ethanol. All other fixed and variable costs besides corn cost and by-product prices were held constant.

For example, using current U.S. RFG and oxygenated gasoline demand (1.84 million b/d and 280,000 b/d respectively, excluding California), the U.S. excluding California would require approximately 127,000 b/d of ethanol. Therefore, ethanol production would need to increase some 27,000 b/d from its current level of 100,000 b/d to satisfy this demand. This would require an additional 160 million bushels of corn feedstocks, increasing the price of corn some 7 cents/bushel from the baseline. Additional California ethanol demand on top of this would require more corn feedstocks. California ethanol demand of 50,000 b/d would require almost 300 million bushels of corn, and would lead to an increase in corn prices of 30 cents/bushel from the baseline.

In the long term scenario, ethanol prices are expected to decline to their marginal cost of production as calculated above. Since most production will still be located in the large corn-producing states, the transportation cost of 15 cents/gallon remains.

The calculations for determining the long term costs of corn and by-products are shown in Section G and the formulas for determining the production costs for ethanol producers is explained in Section D.

The price/volume relationships analyzed below are found in Section I, Table I-3. It is assumed that all subsidies including tax credits for blenders are in place throughout the country.

Section B: Derivation of Breakeven Equations

There are several equations used in this report that calculate the breakeven price level for different oxygenates. They are all based on the derivation of the same equation, which first appears in Section 4.1.3.1, in determining the supply curve for ethanol delivered to California in the intermediate term (California-only ban of MTBE). This equation was developed by Mathpro, Inc.

While the equation below is used for determining the breakeven price of ethanol, it can also be used to determine the breakeven level of TAME or TBA. The co-efficients (used to determine the percentage of oxygenate needed to achieve either a 2.0 weight % or 2.7 weight % oxygen level in gasoline) will change, as will the values for the RVP and octane levels of each oxygenate.

Derivation of Equation for the value of ethanol in oxygenated gasoline

1. Initial identity

$$.852\ P_{B\text{-}MTBE} + .148\ P_{MTBE} = .923\ P_{B\text{-}EOH} + .077\ P_{EOH} + C_{EOH}$$

Solve for P_{EOH} $\quad P_{EOH} = (.852\ P_{B\text{-}MTBE} - .923\ P_{B\text{-}EOH} + .148\ P_{MTBE} - C_{EOH}) / .077$

Where $P_{B\text{-}MTBE}$ = Price of reformulated blendstock for oxygenate blending (RBOB) for MTBE blending

$P_{B\text{-}EOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) for Ethanol blending

P_{MTBE} = Price of MTBE

P_{EOH} = Price of ethanol

C_{EOH} = Any costs associated with ethanol blending

Co-efficients set up for ethanol and MTBE blending to achieve a 2.7 wt % oxygen level in gasoline.

2. Equations for determining change in octane in RBOBs (pool octane assumed to be 89 octane)

A. MTBE: $\quad .852\ O_{B\text{-}MTBE} + .148\ O_{MTBE} = 89$

$$O_{B\text{-}MTBE} = (89 - .148\ O_{MTBE}) / .852$$

$$?\ O_{B\text{-}MTBE} = 89 - [\ (89 - .148\ O_{MTBE}) / .852\ ]$$

$$?\ O_{B\text{-}MTBE} = 3.65$$

Where $O_{B\text{-}MTBE}$ = Octane of RBOB used for blending MTBE (assumed equal to average pool octane)

O_{MTBE} = Octane of MTBE (110 octane)

? $O_{B\text{-}MTBE}$ = Reduction in octane of RBOB used for blending MTBE

Co-efficients of .852 and .148 set up for MTBE blending to achieve a 2.7 weight % oxygen level

B. Ethanol: $.923\ O_{B\text{-}EOH} + .077\ O_{EOH} = 89$

$$O_{B\text{-}EOH} = (89 - .077\ O_{EOH}) / .923$$

$$?\ O_{B\text{-}EOH} = 89 - [\ (89 - .077\ O_{EOH}) / .923\ ]$$

$$?\ O_{B\text{-}EOH} = 2.17$$

Where $O_{B\text{-}EOH}$ = Octane of RBOB used for blending ethanol

O_{EOH} = Octane of Ethanol (115 octane)

? $O_{B\text{-}EOH}$ = Reduction in octane of RBOB used for blending ethanol

Co-efficients of .923 and .077 set up for ethanol blending to achieve a 2.7 weight % oxygen level

2. Equations for determining change in RVP in RBOBs

A. MTBE: $.852\ RVP_{B\text{-}MTBE} + .148\ RVP_{MTBE} = RVP_{POOL}$

$$?\ RVP_{B\text{-}MTBE} = RVP_{POOL} - [\ (RVP_{POOL} - .148\ RVP_{MTBE}) / .852\ ]$$

$$?\ RVP_{B\text{-}MTBE} = -.174\ RVP_{POOL} + 1.39$$

Where $RVP_{B\text{-}MTBE}$ = RVP of RBOB used for blending MTBE

RVP_{MTBE} = RVP of MTBE (8 RVP)

RVP_{POOL} = Pool gasoline RVP

B. Ethanol: $.923\ RVP_{B\text{-}EOH} + .077\ RVP_{EOH} = RVP_{POOL}$

$$?\ RVP_{B\text{-}EOH} = RVP_{POOL} - [\ (RVP_{POOL} - .077\ RVP_{EOH}) / .923\ ]$$

$$?\ RVP_{B\text{-}EOH} = -.083\ RVP_{POOL} + 1.50$$

Where $RVP_{B\text{-}EOH}$ = RVP of RBOB used for blending ethanol
RVP_{EOH} = RVP of ethanol (18 RVP)
RVP_{POOL} = Pool gasoline RVP

3. Equations for estimating value of RBOBs

A. MTBE: $P_{B\text{-}MTBE} = P_{POOL} - (P_{OCT} * ?O_{B\text{-}MTBE} + P_{RVP} * ?RVP_{MTBE})$

B. Ethanol $P_{B\text{-}EOH} = P_{POOL} - (P_{OCT} * ?O_{B\text{-}EOH} + P_{RVP} * ?RVP_{EOH})$

Where $P_{B\text{-}MTBE}$ = Price of RBOB used for blending MTBE
$P_{B\text{-}EOH}$ = Price of RBOB used for blending ethanol
P_{POOL} = Price of pool gasoline
P_{OCT} = Price of octane
$?O_{B\text{-}MTBE}$ = Reduction in octane of RBOB used for blending MTBE
$?O_{B\text{-}EOH}$ = Reduction in octane of RBOB used for blending ethanol
P_{RVP} = Price of RVP

NOTE: These RBOB values are plugged into the initial identity, to solve for the price of ethanol.

Note on octane prices: In determining the breakeven level of ethanol (or other oxygenates) using the equations above, the following values for octane prices were used. In scenarios that covered oxygenates used in summer, octane was assumed to be worth 1 cent per octane number. For wintertime, octane was assumed to be worth 0.4 cents per octane number. In scenarios that covered oxygenate usage on a year-round basis, a simple average was used for the octane price (0.7 cents per octane number).

Note on RVP prices: In determining the breakeven level of ethanol (or other oxygenates) using the equations above, the following values for RVP prices were used. In scenarios that covered oxygenates used in summer, RVP was assumed to be worth -0.3 cents per RVP number (RVP value is negative in the summer because blenders need to limit RVP levels to comply with air quality regulations). For wintertime, RVP was assumed to be worth 0.3 cents per RVP number. In scenarios that covered oxygenate usage on a year-round basis, a simple average was used for the RVP value (0.0 cents per RVP number).

Derivation of Equation for the value of ethanol in regular gasoline ("gasohol")

The following equation, also developed by Mathpro, Inc., estimates the value of ethanol used as a gasoline extender in regular gasoline commonly known as gasohol. This equation is only used in Section 4.1.3.1, and calculates the price at which California blenders can bid ethanol away from blenders in States that use gasohol.

1. Initial identity:

$$P_{R\text{-}MOGAS} - P_{MOGAS} = P_{R\text{-}GASOHOL} - .9\, P_{B\text{-}EOH} - .1\, P_{EOH} - C_{EOH}$$

Solve for P_{EOH}

$$P_{EOH} = -(P_{R\text{-}MOGAS} - P_{MOGAS} - P_{R\text{-}GASOHOL} + .9\, P_{B\text{-}EOH} + C_{EOH}) / 0.1$$

Where P_{EOH} = Price of ethanol
$P_{B\text{-}EOH}$ = Price of RBOB used for blending ethanol
$P_{R\text{-}MOGAS}$ = Retail (pump) price of pool gasoline
$P_{R\text{-}GASOHOL}$ = Retail (pump) price of gasohol
P_{MOGAS} = Rack price of pool gasoline
C_{EOH} = Any costs associated with blending ethanol (assumed zero)

2. Equations for determining change in octane in ethanol RBOB (pool octane assumed to be 89 octane)

$$.9\, O_{B\text{-}EOH} + .1\, O_{EOH} = 89$$

$$O_{B\text{-}EOH} = (89 - .1\, O_{EOH}) / .9$$

$$?\, O_{B\text{-}EOH} = 89 - [(89 - .1\, O_{EOH}) / .9]$$

$$?\, O_{B\text{-}EOH} = 2.89$$

Where $O_{B\text{-}EOH}$ = Octane of RBOB used for blending ethanol
O_{EOH} = Octane of Ethanol (115 octane)
$?\, O_{B\text{-}EOH}$ = Reduction in octane of RBOB used for blending ethanol

Co-efficients of .9 and .1 set up for ethanol blending to achieve a 3.5 weight % oxygen level commonly used in gasohol.

3. Equation for determining the retail price of gasohol

The pump price of gasohol is discounted from the pump price of regular pool gasoline since the consumer must be compensated for the fact that gasohol has a lower energy content than regular gasoline. This is due to the fact that ethanol's energy density is equal to roughly 3.55 million BTUs per barrel, whereas pool gasoline's energy density is equal to 5.25 million BTU's per barrel. Therefore, the ratio of ethanol to pool gasoline energy density is 0.68, which is used in the equation below, which states that gasohol's retail price must be equal to 90 percent of pool gasoline's retail price plus 10 percent of pool gasoline's retail price adjusted for the lower energy content due to the presence of the 10 percent ethanol blend:

$$P_{R\text{-}GASOHOL} = (.9 + .1*.68) * P_{R\text{-}MOGAS}$$

2. Equations for estimating value of ethanol RBOB:

$$P_{B\text{-}EOH} = P_{POOL} - (P_{OCT} * ?\,O_{B\text{-}EOH})$$

Where $P_{B\text{-}EOH}$ = Price of RBOB used for blending ethanol
P_{POOL} = Price of pool gasoline
P_{OCT} = Price of octane
$?\,O_{B\text{-}EOH}$ = Reduction in octane of RBOB used for blending ethanol

3. After solving for the value of the ethanol RBOB and the value of gasohol, these inputs are plugged into the initial identity above, and solved for the price of ethanol. Throughout this study, the cost of blending with ethanol is assumed to be zero, and there is assumed to be zero consumer bias against ethanol.

Section C: Gasoline Price Data

State by state gasoline price data									
Rack Price Data				**Retail Price and Tax Data**					
State	**Rack Price**	**Delta**		**State**	**Retail**	**State Tax**	**Fed Tax**	**Pump Price**	**Delta**
LA	46.9			GA	60.4	7.5	18.4	89.45	
MS	47.3	0.4		SC	60.7	16	18.4	95.10	5.65
TX	47.7	0.8		OK	60.4	17	18.4	95.80	6.35
GA	47.9	1.0		MO	60.4	17	18.4	95.80	6.35
SC	48.3	1.4		FL	65.4	13.1	18.4	96.90	7.45
FL	48.3	1.4		KS	61.5	18	18.4	97.90	8.45
NC	48.4	1.5		AR	61.5	18.6	18.4	98.50	9.05
AL	48.4	1.5		NJ	69.7	10.5	18.4	98.60	9.15
OK	48.4	1.5		TX	61.9	20	18.4	100.30	10.85
AR	48.5	1.6		IA	62.2	20	18.4	100.60	11.15
VA	48.5	1.6		TN	62.4	20	18.4	100.80	11.35
TN	48.7	1.8		KY	66.1	16.4	18.4	100.90	11.45
IN	48.9	2.0		VA	65.7	17.5	18.4	101.60	12.15
KS	48.9	2.0		IN	65.0	15	18.4	101.65	12.20
MO	48.9	2.0		NC	63.0	21.2	18.4	102.60	13.15
PA	49.1	2.2		AL	66.3	18	18.4	102.70	13.25
OH	49.3	2.4		LA	65.2	20	18.4	103.60	14.15
MI	49.7	2.8		MS	67.1	18.4	18.4	103.90	14.45
DE	50.0	3.1		NE	63.6	22.8	18.4	104.80	15.35
KY	50.1	3.2		MI	62.9	19	18.4	105.18	15.73
WI	50.4	3.5		DE	65.1	23	18.4	106.50	17.05
NE	50.4	3.5		PA	62.2	25.9	18.4	106.50	17.05
NY	50.5	3.6		VT	68.5	20	18.4	106.90	17.45
VT	50.5	3.6		NH	69.0	19.5	18.4	106.90	17.45
IL	50.6	3.7		SD	70.6	18	18.4	107.00	17.55
IA	50.8	3.9		OH	66.7	22	18.4	107.10	17.65
ND	50.9	4.0		MA	68.0	21	18.4	107.40	17.95
MD	51.1	4.2		MD	66.5	23.5	18.4	108.40	18.95
SD	51.4	4.5		WV	65.3	25.35	18.4	109.05	19.60
WV	51.6	4.7		WI	65.4	25.4	18.4	109.20	19.75
RI	51.6	4.7		ME	72.2	19	18.4	109.60	20.15
NH	51.8	4.9		IL	68.3	19	18.4	109.97	20.52
ME	52.2	5.3		ND	72.1	20	18.4	110.50	21.05
NJ	52.2	5.3		MN	72.2	20	18.4	110.60	21.15
MA	52.7	5.8		NY	67.0	22.05	18.4	110.87	21.41
CT	52.7	5.8		RI	63.8	29	18.4	111.20	21.75
MN	54.1	7.2		CT	68.0	32	18.4	118.40	28.95
CO	52.7	5.8							
NM	53.1	6.2							
OR	54.7	7.8							
AZ	54.7	7.8							
WY	55.9	9							
WA	56.1	9.2							
NV	56.5	9.6							
UT	58.1	11.2							
ID	58.5	11.6							
MT	59.6	12.7							
AK	70.4	23.5							

Source: Energy Information Administration, *Petroleum Marketing Annual 1998*.

Section D: Derivation of Ethanol Production costs and producers' margins

Ethanol producers face differing cost structures depending on the feedstock costs (the price of corn for over 90 percent of ethanol producers) and the price producers receive for the by-products of corn milling (distillers' dried grains, corn gluten meal, corn gluten feed, corn germ, CO_2, gypsum, etc.).

In order to determine a notional net production cost for wet milling and dry milling plants, historical data was used for the prices of corn, DDG, corn gluten meal and corn gluten corn. Due to a lack of historical data for corn germ and other minor by-products, these values were held constant. Operating and fixed costs were held constant. Ethanol producers are assumed to produce roughly 2.6 gallons of ethanol from each bushel of corn. Net production cost equals gross expenses minus gross credits.

<u>Dry Milling Operation</u> [4]

Expenses:

- Feedstock (corn) = Corn cost ($/bushel) / 2.6
- Other costs (energy, labor, depreciation, chemicals, fixed costs): .625 cents/gallon

Credits:

- Distillers' dried grains (DDG)= ((DDG cost, $/ton) / 2000 lbs) * (17.35 lbs/bushel of DDG) / 2.6
- Other byproducts = 1 cent/gallon (assumed constant)

<u>Wet Milling Operation</u>

Expenses:

- Feedstock (corn) = Corn cost ($/bushel) / 2.6
- Other costs (energy, labor, depreciation, chemicals, fixed costs): .51 cents/gallon

Credits:

- Corn gluten meal: ((gluten meal cost, $/ton) / 2000 lbs) * (2.8 lbs/bushel of corn) / 2.6
- Corn gluten feed: ((gluten feed cost, $/ton) / 2000 lbs) * (10 lbs/bushel of corn) / 2.6
- Corn germ: ((germ cost, $/ton) / 2000 lbs) * (4 lbs/bushel of corn) / 2.6
- Other byproducts = 1 cent/gallon (assumed constant)

[4] Notional cost structures for wet/dry milling producers provided by Arkenol, Inc.

Section E: Historical Prices for Ethanol Production

The following prices were used to construct historical ethanol net production costs using the notional formula supplied above. Historical price data for germ was not available; a constant value of $250/ton was used instead.

All other prices provided by *Hart's Publications*.

	Ethanol Price $/gallon	**Corn Price $/bu**	**Corn Price $/gallon**	**DDG ($/ton)**	**Gluten Meal $/ton**	**Gluten Feed $/ton**	**Germ $/ton**
January-92	$1.18	$2.54	$0.98	$124.00	$270.63	$105.00	$250.00
February	$1.19	$2.62	$1.01	$125.13	$271.88	$107.50	$250.00
March	$1.20	$2.67	$1.03	$123.50	$277.50	$107.50	$250.00
April	$1.24	$2.56	$0.99	$117.13	$252.50	$108.50	$250.00
May	$1.26	$2.58	$0.99	$115.38	$245.00	$106.00	$250.00
June	$1.27	$2.63	$1.01	$115.38	$247.50	$108.50	$250.00
July	$1.28	$2.47	$0.95	$120.38	$245.63	$108.50	$250.00
August	$1.33	$2.29	$0.88	$123.00	$242.70	$108.50	$250.00
September	$1.34	$2.26	$0.87	$125.25	$264.38	$108.50	$250.00
October	$1.36	$2.17	$0.84	$125.98	$270.25	$106.50	$250.00
November	$1.38	$2.17	$0.83	$126.42	$267.38	$103.00	$250.00
December	$1.29	$2.43	$0.93	$128.44	$267.50	$106.00	$250.00
January-93	$1.19	$2.30	$0.88	$129.67	$288.33	$103.50	$250.00
February	$1.15	$2.25	$0.87	$131.50	$283.40	$96.00	$250.00
March	$1.14	$2.25	$0.86	$123.55	$296.00	$97.00	$250.00
April	$1.15	$2.29	$0.88	$112.50	$288.13	$95.00	$250.00
May	$1.18	$2.26	$0.87	$106.60	$279.88	$95.00	$250.00
June	$1.18	$2.20	$0.84	$104.88	$275.63	$95.00	$250.00
July	$1.11	$2.38	$0.92	$108.17	$294.17	$95.00	$250.00
August	$1.10	$2.46	$0.95	$111.90	$313.00	$95.00	$250.00
September	$1.10	$2.40	$0.92	$113.00	$308.13	$96.50	$250.00
October	$1.11	$2.52	$0.97	$115.70	$298.45	$95.00	$250.00
November	$1.06	$2.71	$1.04	$121.38	$304.69	$92.50	$250.00
December	$1.01	$2.79	$1.07	$124.67	$313.33	$92.50	$250.00
January-94	$1.04	$3.02	$1.16	$126.00	$314.38	$97.80	$250.00
February	$1.12	$3.03	$1.16	$127.00	$298.13	$94.50	$250.00
March	$1.11	$2.88	$1.11	$124.40	$289.50	$97.00	$250.00
April	$1.10	$2.72	$1.05	$123.00	$283.75	$98.50	$250.00
May	$1.11	$2.70	$1.04	$121.75	$265.00	$101.00	$250.00
June	$1.14	$2.82	$1.08	$119.34	$262.70	$101.00	$250.00
July	$1.18	$2.40	$0.92	$121.25	$264.38	$97.50	$250.00
August	$1.22	$2.26	$0.87	$119.38	$259.38	$102.50	$250.00
September	$1.22	$2.26	$0.87	$118.90	$240.50	$102.50	$250.00
October	$1.22	$2.16	$0.83	$120.63	$225.00	$102.50	$250.00
November	$1.24	$2.18	$0.84	$118.88	$229.38	$103.50	$250.00
December	$1.25	$2.19	$0.84	$113.13	$237.50	$107.50	$250.00
January-95	$1.22	$2.27	$0.87	$108.50	$236.25	$108.50	$250.00
February	$1.20	$2.32	$0.89	$99.88	$225.63	$108.50	$250.00
March	$1.14	$2.39	$0.92	$95.10	$218.00	$108.50	$250.00

April	$1.11	$2.48	$0.95	$93.25	$210.00	$108.50	$250.00
May	$1.12	$2.56	$0.98	$93.28	$192.50	$108.50	$250.00

Section E, con't: Historical Prices for Ethanol Production:

	Ethanol Price $/gallon	Corn Price $/bu	Corn Price $/gallon	DDG ($/ton)	Gluten Meal $/ton	Gluten Feed $/ton	Germ $/ton
June	$1.10	$2.76	$1.06	$95.20	$207.50	$107.30	$250.00
July	$1.07	$2.93	$1.13	$98.13	$211.88	$108.50	$250.00
August	$1.09	$2.86	$1.10	$100.60	$228.50	$106.50	$250.00
September	$1.11	$2.95	$1.13	$106.20	$244.25	$105.50	$250.00
October	$1.13	$3.11	$1.19	$123.25	$270.63	$105.50	$250.00
November	$1.17	$3.37	$1.30	$136.70	$316.80	$105.00	$250.00
December	$1.20	$3.46	$1.33	$140.33	$332.50	$107.50	$250.00
January-96	$1.25	$3.63	$1.39	$139.88	$337.50	$107.50	$250.00
February	$1.26	$3.86	$1.48	$142.60	$343.90	$107.50	$250.00
March	$1.24	$4.03	$1.55	$145.88	$342.38	$107.50	$250.00
April	$1.28	$4.58	$1.76	$152.63	$334.88	$107.50	$250.00
May	$1.37	$4.91	$1.89	$178.70	$342.40	$107.50	$250.00
June	$1.38	$4.84	$1.86	$178.88	$323.13	$107.50	$250.00
July	$1.43	$4.80	$1.84	$161.83	$307.50	$110.00	$250.00
August	$1.53	$4.65	$1.79	$151.20	$298.00	$110.00	$250.00
September	$1.54	$3.81	$1.47	$151.50	$329.38	$108.10	$250.00
October	$1.49	$2.97	$1.14	$140.20	$344.00	$108.10	$250.00
November	$1.38	$2.69	$1.03	$136.25	$340.00	$103.50	$250.00
December	$1.28	$2.69	$1.04	$140.00	$343.13	$97.50	$250.00
January-97	$1.20	$2.67	$1.03	$147.00	$336.25	$94.00	$250.00
February	$1.20	$2.76	$1.06	$147.38	$335.63	$94.00	$250.00
March	$1.19	$2.94	$1.13	$145.13	$341.25	$85.00	$250.00
April	$1.20	$2.94	$1.13	$131.60	$343.13	$85.00	$250.00
May	$1.20	$2.81	$1.08	$121.00	$352.50	$80.00	$250.00
June	$1.14	$2.67	$1.03	$115.00	$349.25	$79.00	$250.00
July	$1.15	$2.55	$0.98	$115.50	$336.25	$81.50	$250.00
August	$1.20	$2.58	$0.99	$120.50	$345.63	$81.50	$250.00
September	$1.22	$2.57	$0.99	$120.75	$356.25	$81.50	$250.00
October	$1.22	$2.62	$1.01	$118.50	$345.50	$80.50	$250.00
November	$1.22	$2.65	$1.02	$120.75	$351.25	$74.25	$250.00
December	$1.22	$2.63	$1.01	$117.75	$352.38	$78.38	$250.00
January-98	$1.19	$2.65	$1.02	$117.50	$321.88	$77.88	$250.00
February	$1.15	$2.65	$1.02	$100.88	$295.00	$76.50	$250.00
March	$1.07	$2.66	$1.02	$92.38	$273.75	$69.75	$250.00
April	$1.03	$2.50	$0.96	$84.40	$241.50	$64.70	$250.00
May	$1.04	$2.47	$0.95	$77.50	$236.25	$64.63	$250.00

Section F: Ethanol Producers' Historical Notional Expenses, Credits and Margins

The following are notional net production costs for wet milling ethanol producers and dry milling ethanol producers, based on the prices in Section F, and the formulas provided in Section E.

	Wet Milling Operation				Dry Milling Operation			
	Expense	Credit	Net	Margin	Expense	Credit	Net	Margin
January-92	$1.49	$0.64	$0.84	$0.34	$1.60	$0.51	$1.09	$0.09
February	$1.52	$0.65	$0.87	$0.32	$1.63	$0.52	$1.11	$0.08
March	$1.54	$0.65	$0.89	$0.32	$1.65	$0.51	$1.14	$0.06
April	$1.50	$0.64	$0.86	$0.39	$1.61	$0.49	$1.12	$0.12
May	$1.50	$0.63	$0.87	$0.39	$1.62	$0.48	$1.13	$0.13
June	$1.52	$0.64	$0.89	$0.39	$1.64	$0.48	$1.15	$0.12
July	$1.46	$0.64	$0.82	$0.46	$1.58	$0.50	$1.07	$0.21
August	$1.39	$0.64	$0.76	$0.57	$1.51	$0.51	$0.99	$0.33
September	$1.38	$0.65	$0.73	$0.61	$1.49	$0.52	$0.98	$0.37
October	$1.35	$0.65	$0.70	$0.66	$1.46	$0.52	$0.94	$0.42
November	$1.35	$0.64	$0.71	$0.67	$1.46	$0.52	$0.94	$0.44
December	$1.44	$0.64	$0.80	$0.49	$1.56	$0.53	$1.03	$0.26
January-93	$1.39	$0.65	$0.74	$0.45	$1.51	$0.53	$0.98	$0.21
February	$1.38	$0.63	$0.74	$0.41	$1.49	$0.54	$0.95	$0.20
March	$1.37	$0.64	$0.73	$0.41	$1.49	$0.51	$0.98	$0.16
April	$1.39	$0.63	$0.76	$0.39	$1.51	$0.48	$1.03	$0.12
May	$1.38	$0.63	$0.75	$0.43	$1.50	$0.46	$1.04	$0.14
June	$1.36	$0.63	$0.73	$0.45	$1.47	$0.45	$1.02	$0.16
July	$1.43	$0.64	$0.79	$0.32	$1.54	$0.46	$1.08	$0.03
August	$1.46	$0.65	$0.81	$0.29	$1.57	$0.47	$1.10	($0.00)
September	$1.43	$0.65	$0.78	$0.31	$1.55	$0.48	$1.07	$0.03
October	$1.48	$0.64	$0.84	$0.27	$1.59	$0.49	$1.11	($0.00)
November	$1.55	$0.64	$0.92	$0.14	$1.67	$0.50	$1.16	($0.10)
December	$1.58	$0.64	$0.94	$0.07	$1.70	$0.52	$1.18	($0.18)
January-94	$1.67	$0.65	$1.02	$0.02	$1.78	$0.52	$1.26	($0.22)
February	$1.68	$0.64	$1.04	$0.08	$1.79	$0.52	$1.27	($0.15)
March	$1.62	$0.64	$0.98	$0.13	$1.73	$0.52	$1.22	($0.11)
April	$1.56	$0.64	$0.92	$0.18	$1.67	$0.51	$1.16	($0.06)
May	$1.55	$0.63	$0.92	$0.19	$1.66	$0.51	$1.16	($0.05)
June	$1.60	$0.63	$0.96	$0.17	$1.71	$0.50	$1.21	($0.07)
July	$1.44	$0.63	$0.81	$0.37	$1.55	$0.50	$1.05	$0.13
August	$1.38	$0.63	$0.75	$0.48	$1.49	$0.50	$1.00	$0.23
September	$1.38	$0.62	$0.76	$0.46	$1.50	$0.50	$1.00	$0.22
October	$1.34	$0.61	$0.73	$0.49	$1.45	$0.50	$0.95	$0.27
November	$1.35	$0.62	$0.73	$0.51	$1.46	$0.50	$0.97	$0.27
December	$1.35	$0.63	$0.72	$0.53	$1.47	$0.48	$0.99	$0.26
January-95	$1.38	$0.63	$0.75	$0.47	$1.50	$0.46	$1.03	$0.19
February	$1.40	$0.63	$0.78	$0.42	$1.52	$0.43	$1.08	$0.11
March	$1.43	$0.62	$0.81	$0.33	$1.54	$0.42	$1.13	$0.01
April	$1.46	$0.62	$0.85	$0.27	$1.58	$0.41	$1.17	($0.05)
May	$1.50	$0.61	$0.89	$0.23	$1.61	$0.41	$1.20	($0.08)
June	$1.57	$0.61	$0.96	$0.14	$1.69	$0.42	$1.27	($0.17)
July	$1.64	$0.62	$1.02	$0.05	$1.75	$0.43	$1.32	($0.25)

August	$1.61	$0.62	$0.99	$0.10	$1.73	$0.44	$1.29	($0.20)

Section F, con't: Ethanol Producers' Historical Notional Expenses, Credits and Margins

	Wet Milling Operation				Dry Milling Operation			
	Expense	**Credit**	**Net**	**Margin**	**Expense**	**Credit**	**Net**	**Margin**
September	$1.64	$0.63	$1.01	$0.09	$1.76	$0.45	$1.30	($0.20)
October	$1.71	$0.65	$1.06	$0.07	$1.82	$0.51	$1.31	($0.17)
November	$1.81	$0.67	$1.14	$0.03	$1.92	$0.56	$1.37	($0.20)
December	$1.84	$0.68	$1.16	$0.04	$1.96	$0.57	$1.39	($0.19)
January-96	$1.91	$0.69	$1.22	$0.03	$2.02	$0.57	$1.45	($0.20)
February	$1.99	$0.69	$1.31	-$0.05	$2.11	$0.58	$1.53	($0.28)
March	$2.06	$0.69	$1.37	-$0.13	$2.17	$0.59	$1.59	($0.35)
April	$2.27	$0.68	$1.59	-$0.30	$2.38	$0.61	$1.78	($0.49)
May	$2.40	$0.69	$1.71	-$0.34	$2.51	$0.70	$1.82	($0.45)
June	$2.37	$0.68	$1.70	-$0.31	$2.49	$0.70	$1.79	($0.41)
July	$2.36	$0.67	$1.68	-$0.26	$2.47	$0.64	$1.83	($0.40)
August	$2.30	$0.67	$1.63	-$0.10	$2.41	$0.60	$1.81	($0.28)
September	$1.98	$0.68	$1.30	$0.24	$2.09	$0.61	$1.49	$0.05
October	$1.65	$0.69	$0.96	$0.53	$1.77	$0.57	$1.20	$0.29
November	$1.55	$0.68	$0.87	$0.51	$1.66	$0.55	$1.10	$0.27
December	$1.55	$0.67	$0.88	$0.40	$1.66	$0.57	$1.09	$0.19
January-97	$1.54	$0.66	$0.88	$0.32	$1.65	$0.59	$1.06	$0.13
February	$1.57	$0.66	$0.91	$0.28	$1.69	$0.59	$1.09	$0.10
March	$1.64	$0.64	$1.00	$0.20	$1.76	$0.58	$1.17	$0.02
April	$1.64	$0.65	$1.00	$0.20	$1.76	$0.54	$1.22	($0.02)
May	$1.59	$0.64	$0.95	$0.25	$1.71	$0.50	$1.20	($0.01)
June	$1.54	$0.64	$0.90	$0.24	$1.65	$0.48	$1.17	($0.03)
July	$1.49	$0.64	$0.86	$0.30	$1.61	$0.49	$1.12	$0.03
August	$1.50	$0.64	$0.86	$0.34	$1.62	$0.50	$1.11	$0.09
September	$1.50	$0.65	$0.85	$0.37	$1.61	$0.50	$1.11	$0.11
October	$1.52	$0.64	$0.88	$0.34	$1.63	$0.50	$1.14	$0.09
November	$1.53	$0.63	$0.90	$0.32	$1.64	$0.50	$1.14	$0.08
December	$1.52	$0.64	$0.89	$0.34	$1.64	$0.49	$1.14	$0.08
January-98	$1.53	$0.62	$0.91	$0.28	$1.64	$0.49	$1.15	$0.04
February	$1.53	$0.60	$0.93	$0.22	$1.64	$0.44	$1.21	($0.06)
March	$1.54	$0.58	$0.96	$0.12	$1.65	$0.41	$1.24	($0.17)
April	$1.47	$0.55	$0.92	$0.11	$1.59	$0.38	$1.20	($0.17)
May	$1.46	$0.55	$0.91	$0.12	$1.57	$0.36	$1.21	($0.18)

Average wet milling production cost: $.95/gallon
Average dry milling production cost: $1.19/gallon

Weighted ethanol producers notional net production cost (67% wet milling, 33% dry milling): $1.03/gallon

Section G: Calculation of long term byproduct elasticities and long term cost of ethanol

In determining the long term net production cost of ethanol, increased ethanol demand is assumed to increase the price of corn while decreasing the received price for ethanol production by-products, such as distillers' dried grains (DDG), corn gluten meal, corn gluten feed, and corn germ. Long term elasticity values are used to determine the effect on the long term prices of corn and corn byproducts.

The long term elasticity of corn was supplied by the U.S. Department of Agriculture as 0.3. This is defined as the change in supply divided by the change in price. Roughly speaking, this equates to an increase of 5 cents/bushel for every 100 million bushels of additional corn used for ethanol production. For the by-products, secondary source data was used to estimate elasticity values. A USDA report from 1993 estimated the decrease in price of byproducts caused by an increase in ethanol demand (and thus an increase in corn processing). This report estimated that a change in ethanol production from 1.2 billion gallons to 5 billion gallons (a change of 3.8 billion gallons) over 7 years would cause the price of corn gluten meal to fall 7 percent, corn gluten feed to fall 12.3 percent, and distillers' dried grains to fall 4 percent. No estimation was provided for germ; an average of the price decline of corn gluten meal and corn gluten feed was assumed as a proxy (a decline of 7.7 percent). Wet milling production (which supplies byproducts of corn germ, corn gluten meal and corn gluten feed) was assumed to remain at 67 percent of national ethanol production, while dry milling production (which supplies byproduct of DDG) was assumed to remain at 33 percent of national ethanol production. Thus the base ethanol demand (1.2 billion gallons) and increase in ethanol demand (3.8 billion gallons) are multiplied by .33 for determining the change in DDG supply and .67 for determining the change in all other byproduct supplies. The elasticity calculations are provided below:

DDG (17.35 lbs per bushel at 10% moisture)

	Change in ethanol demand	In bushels of corn	In tons of DDG
Change	1,254,000,000	482,307,692	4,184,019
Base	396,000,000	152,307,692	1,321,269
% Change in Supply			317%
Change in Price			4%
Elasticity (e = ? P / ? S)			0.0126

Gluten meal (2.88 lbs per bushel at 10% moisture)

	Change in ethanol demand	In bushels of corn	In tons of gluten meal
Change	2,546,000,000	979,230,769	1,410,092
Base	804,000,000	309,230,769	445,292
% Change in Supply			317%
Change in Price			7%
Elasticity (e = ? P / ? S)			0.0221

Section G, con't: Calculation of long term byproduct elasticities and long term cost of ethanol

Gluten feed (10 lbs per bushel at 12% moisture)

	Change in ethanol demand	In bushels of corn	In tons of gluten feed
Change	2,546,000,000	979,230,769	4,896,154
Base	804,000,000	309,230,769	1,546,154
% Change in Supply			317%
Change in Price			12.3%
Elasticity (e = ? P / ? S)			0.0388

Germ (4 lbs per bushel at 2% moisture)

	Change in ethanol demand	In bushels of corn	In tons of germ
Change	2,546,000,000	979,230,769	1,958,462
Base	804,000,000	309,230,769	618,462
% Change in Supply			317%
Change in Price			7.7%
Elasticity (e = ? P / ? S)			0.0243

In order to determine the long term cost of ethanol, the elasticities as calculated above are applied to changes in ethanol demand. The resulting net production costs for wet millers and dry millers are calculated below. The assumptions are a base U.S. corn production level of 10.1 billion bushels, a base corn price of $2.60/bushel, and base byproduct prices of : $118.5 per ton for DDGs, $283.7 per ton for corn gluten meal, $97.4 per ton for corn gluten feed, and $250 per ton for corn germ. These base price assumptions were taken from the average historical prices provided above in Section E, excluding the period of Oct. 1995-Sept. 1996 during which corn prices were abnormally high. Three ethanol demand levels are listed below: 10,000 b/d, 50,000 b/d and 100,000 b/d.

Total new ethanol demand (b/d):	**10,000**	**50,000**	**100,000**
In gallons/year:	153,300,000	766,500,000	1,533,000,000
Additional bushels required:	58,961,538	294,807,692	589,615,385
Price reaction (? P = ? S / e):	1.46%	7.30%	14.59%
Price of corn:	$2.638	$2.79	$2.979
in $/gallon of ethanol	$1.015	$1.073	$1.146

Section G, con't: Calculation of long term byproduct elasticities and long term cost of ethanol

Negative change in DDG price			
(? P = e * ? S)	0.16%	0.81%	1.61%
Price of DDG	$118.31	$117.54	$116.58
in $/gallon of ethanol	$0.395	$0.392	$0.389
Negative change in gluten meal price			
(? P = e * ? S)	0.28%	1.41%	2.82%
gluten meal price	$282.90	$279.69	$275.69
in $/gallon of ethanol	$0.157	$0.155	$0.153
Negative change in gluten feed price			
(? P = e * ? S)	0.50%	2.48%	4.96%
gluten feed price	$96.91	$94.98	$92.56
in $/gallon of ethanol	$0.186	$0.183	$0.178
Negative change in germ price			
(? P = e * ? S)	0.31%	1.55%	3.11%
germ price	$249.22	$246.12	$242.23
in $/gallon of ethanol	$0.192	$0.189	$0.186
Expenses (WET MILL)	$1.53	$1.58	$1.66
Credits (WET MILL)	$0.53	$0.53	$0.52
Net production cost (WET MILL)	$0.99	$1.06	$1.14
Expenses (DRY MILL)	$1.64	$1.70	$1.77
Credits (DRY MILL)	$0.39	$0.39	$0.39
Net production cost (DRY MILL)	$1.24	$1.31	$1.38
Weighted average			
(67% wet mill, 33% dry mill)	$1.07	$1.14	$1.22
Ethanol price			
minus subsidy of $.54/gallon	$0.53	$0.60	$0.68

Section H: U.S. Ethanol Plants

Table H- 1

U. S. Ethanol Capacity, 1999				
State	Company	Location	Million gallons per year	Barrels/day
IL	ADM	Decatur	210.0	13,699
IL	ADM	Peoria	200.0	13,046
IA	ADM	Cedar Rapids	200.0	13,046
IA	ADM	Clinton	160.0	10,437
IL	Williams Energy Services	Pekin	100.0	6,523
IN	New Energy Co. of Indiana	South Bend	85.0	5,545
NE	Minnesota Corn Processors	Columbus	80.0	5,219
NE	Cargill	Blair	75.0	4,892
IL	Midwest Grain Products	Pekin	72.2	4,712
TN	A.E. Staley	Louden	45.0	2,935
MN	Minnesota Corn Processors	Marshall	40.0	2,609
IA	Cargill	Eddyville	30.0	1,957
NE	High Plains Corp.	York	30.0	1,957
NM	High Plains Corp.	Portales	30.0	1,957
NE	AGP	Hastings	30.0	1,957
NE	Williams Energy Services	Aurora	30.0	1,957
MN	Exol Corporation - Agri Resources	Albert Lea	30.0	1,957
NE	Chief Ethanol	Hastings	29.0	1,892
KS	High Plains Corp.	Colwich	20.0	1,305
MN	Chippewa Valley Ethanol Company	Benson	18.0	1,174
MN	Corn Plus	Winnebago	17.5	1,142
MN	Heartland Corn Products	Winthrop	16.0	1,044
MN	Ethanol 2000	Bingham Lake	15.0	978
MN	Al-Corn	Claremont	15.0	978
MN	Central Minnesota Ethanol Coop	Little Falls	15.0	978
MN	Agri-Energy, LLC	Luverne	12.0	783
MN	Pro-Corn, LLC	Preston	12.0	783
MN	Minnesota Energy	Buffalo Lake	12.0	783
SD	Heartland Grain Fuels	Huron	12.0	783
ND	Alchem	Grafton	11.0	718
IA	Grain Processing Corporation	Muscatine	10.0	652
KY	Parallel Products	Louisville	10.0	652
KS	Reeve Agri-Energy	Garden City	10.0	652
SD	Heartland Grain Fuel	Aberdeen	8.0	522
MN	Morris Ag Energy	Morris	8.0	522
KS	Midwest Grain Products	Atchinson	7.2	470
SD	Broin Enterprises	Scotland	7.0	457
IA	Manildra	Hamburg	7.0	457
WY	Brimm Energy Inc. (Wyoming Ethanol)	Torrington	5.0	326
WI	Eco Products of Plover, Inc.	Plover	4.0	261
WA	Georgia-Pacific Corp	Bellingham	3.5	228
ID	J.R. Simplot	Caldwell	3.0	196

U. S. Ethanol Capacity, 1999				
State	Company	Location	Million gallons per year	Barrels/day
ID	J.R. Simplot	Heyburn	3.0	196
CA	Golden Cheese of CA	Corona	3.0	196
MN	Kraft, Inc.	Melrose	3.0	196
CA	Parallel Products	Rancho Cucamonga	2.0	130
CO	Merrick and Co.	Golden	1.5	98
IA	Permeate Refining	Hopkinton	1.5	98
MN	Minnesota Clean Fuels	Dundas	1.5	98
KS	ESE Alchohol	Leoti	1.1	72
TX	Jonton Alcohol	Edinburg	1.1	72
WA	Pabst Brewing	Olympia	0.7	46
IL	Vienna Correctional	Vienna	0.5	33
		TOTAL	**1753.3**	**114,400**
Source: Renewable Fuels Association, company data, various other sources				

Table H- 2

U. S. Ethanol Capacity, 1999 Under Construction or Engineering Phase				
State	Company	Location	Million gallons/Year	Barrels/day
MO	Northeast Missouri Grain Processors	Macon	13	848
MT	American Agri-Technology	Great Falls	30	1,957
NE	Nebraska Nutrients Inc.	Sutherland	15	978
IA	Sunrise Energy Ethanol	Iowa	5	326
IL	Adkins Energy Cooperative	Lena	30	1,957
LA	BC International	Jennings	20	1,305
IA		Blairstown	9	587
		TOTAL	**122**	**7,958**
Source: Renewable Fuels Association, company data, various other sources				

Table H- 3

U. S. Ethanol Capacity, 1999 Proposed or Unknown Phase				
State	Company	Location	Million gallons/Year	Barrels/day
MO	Golden Triangle Energy Cooperative	St Joseph	15	978
MN	RDO	Park Rapids	15	978
MN	Dawson Project	Dawson	20	1,305
MN	Renewable Oxygenates, Inc.	Madison	15	978
CA	Arkenol	Sacramento	12	783
CA	Quincy Library Group		20	1,305
CA	Gridley Project		12	783
IL	Unknown *	Pearl City	30	1,957
WA	Unknown *		40	2,609
IL	Unknown *		100	6,523
CA	Unknown *		30	1,957
NY	Unknown *		10	652

OR	Unknown *		30	1,957
SD	Unknown *	Black Hills	12	783
		TOTAL:	**361**	**23,550**

Source: Renewable Fuels Association, company data, various other sources
* Source: Williams Energy presentation before MTBE Blue Ribbon Panel

Section I: Supply Curve Tables (Price/Volume Relationships)

Table I- 1

Ethanol Delivered to California Intermediate Term California Ban of MTBE				
Incremental Volume	Cumulative Volume	Price (cents/gallon)	With 54 cent Subsidy	Delivered cost to California
8,824	8,824	69.8	123.8	123.8
4,300	13,183	67.2	121.2	136.2
1,498	14,682	67.2	121.2	136.2
9,009	23,691	60.0	114.0	136.7
274	23,965	67.7	121.7	136.7
340	24,305	67.7	121.7	136.7
2,379	26,684	67.8	121.8	136.8
3,547	30,231	67.8	121.8	136.8
2,325	32,555	68.2	122.2	137.2
1,895	34,451	68.2	122.2	137.2
4,605	39,056	68.6	122.6	137.6
187	39,242	68.6	122.6	137.6
1,354	40,629	69.1	123.1	138.1
105	40,733	69.5	123.5	138.5
225	40,959	69.8	123.8	138.8
451	41,409	70.0	124.0	139.0
443	41,853	70.4	124.4	139.4
894	42,747	72.8	126.8	141.8
244	42,991	77.0	131.0	146.0
10,955	53,946	77.2	131.2	146.2
3,967	57,913	80.8	134.8	149.8
487	58,400	83.2	137.2	152.2
1,300	59,700	87.8	141.8	156.8
26,524	86,224	88.7	142.7	157.7
1,124	87,348	89.4	143.4	158.4
11,698	99,046	95.6	149.6	164.6
221	99,266	96.4	150.4	165.4
1,603	100,879	97.7	151.7	166.7
920	101,798	99.1	153.1	168.1
4,541	106,339	99.5	153.5	168.5
4,747	111,086	104.1	158.1	173.1

Table I- 2

Ethanol Delivered to California Long Term California Ban of MTBE				
Incremental Volume	Cumulative Volume	Price (cents/gallon)	With 54 cent Subsidy	Delivered cost to California
10,000	10,000	53.5	107.5	122.5
10,000	20,000	55.1	109.1	124.1
10,000	30,000	56.7	110.7	125.7
10,000	40,000	58.3	112.3	127.3
10,000	50,000	59.9	113.9	128.9
10,000	60,000	61.6	115.6	130.6
10,000	70,000	63.2	117.2	132.2
10,000	80,000	64.8	118.8	133.8
10,000	90,000	66.4	120.4	135.4
10,000	100,000	68.0	122.0	137.0
10,000	110,000	69.6	123.6	138.6
10,000	120,000	71.2	125.2	140.2

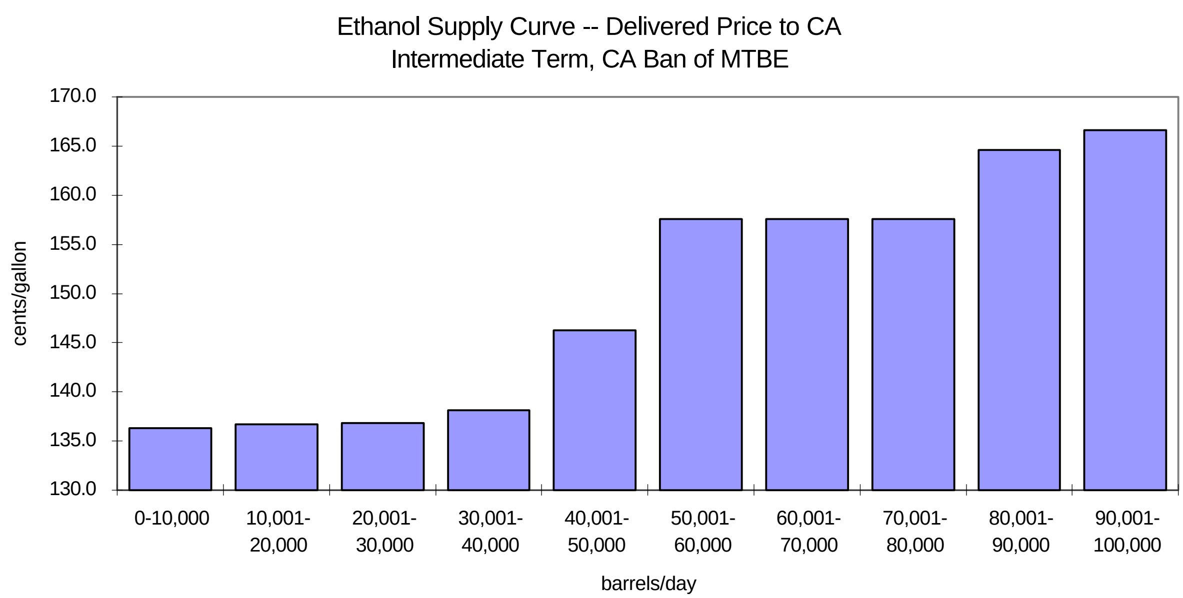
Table I- 3

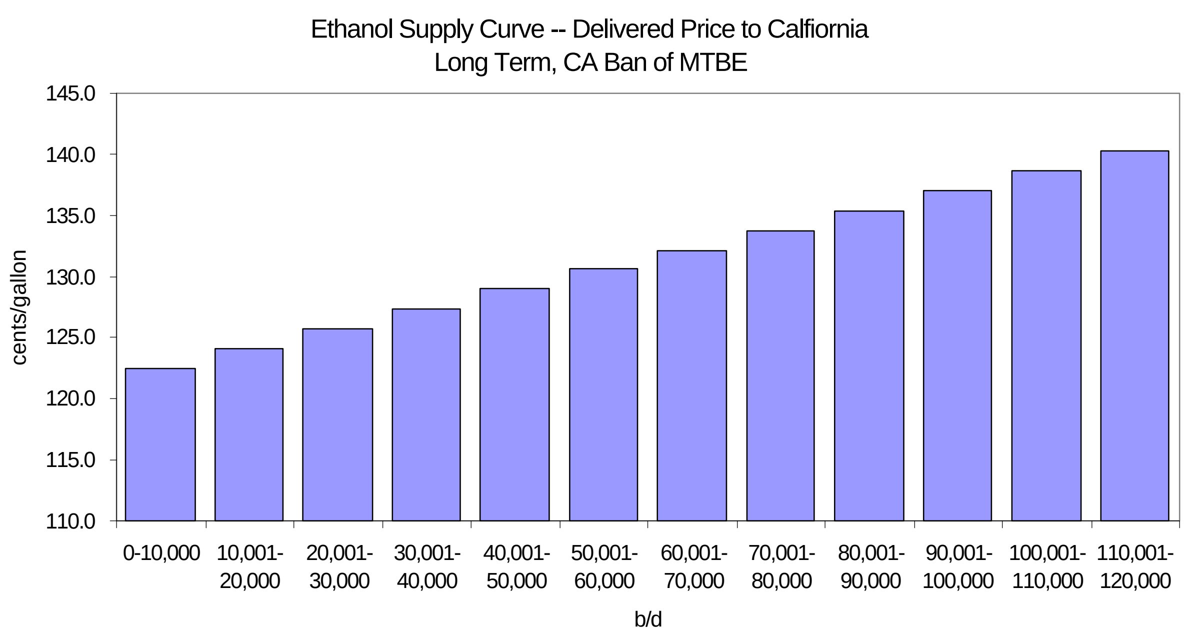
Ethanol Delivered to California Intermediate Term U.S. Ban of MTBE				
Incremental Volume	Cumulative Volume	Price (cents/gallon)	With 54 cent Subsidy	Delivered cost to California
502	502	95.3	149.26	164.26
16,749	17,252	95.7	149.68	164.68
3,952	21,203	97.1	151.06	166.06
46	21,249	97.1	151.14	166.14
164	21,413	98.4	152.41	167.41
5,165	26,578	98.8	152.82	167.82
9,458	36,036	98.8	152.82	167.82
15,472	51,508	99.2	153.25	168.25
1,782	53,290	99.2	153.25	168.25
1,370	54,660	99.6	153.59	168.59
1,935	56,595	99.8	153.77	168.77
1,285	57,880	99.8	153.77	168.77
640	58,520	100.0	153.98	168.98
2,843	61,363	100.1	154.11	169.11
6,588	67,951	100.2	154.19	169.19
10,000	77,951	100.6	154.62	169.62
11,191	89,142	100.7	154.71	169.71
2,669	91,810	100.8	154.80	169.80
1,833	93,644	101.1	155.05	170.05
1,478	95,121	101.1	155.14	170.14
1,820	96,941	101.3	155.30	170.30
1,778	98,719	101.3	155.30	170.30
4,966	103,685	101.9	155.91	170.91
		102.1	156.09	171.09

1,709	105,394			
7,756	113,150	102.4	156.43	171.43
2,335	115,485	103.0	157.01	172.01

Table I- 4

Ethanol Delivered to California Long Term U.S. Ban of MTBE				
Incremental Volume	Cumulative Volume	Price (cents/gallon)	With 54 cent Subsidy	Delivered cost to California
10,000	10,000	58.3	112.3	127.3
10,000	20,000	59.9	113.9	128.9
10,000	30,000	61.6	115.6	130.6
10,000	40,000	63.2	117.2	132.2
10,000	50,000	64.8	118.8	133.8
10,000	60,000	66.4	120.4	135.4
10,000	70,000	68.0	122.0	137.0
10,000	80,000	69.6	123.6	138.6
10,000	90,000	71.2	125.2	140.2
10,000	100,000	72.8	126.8	141.8
10,000	110,000	74.5	128.5	143.5
10,000	120,000	76.1	130.1	145.1


Ethanol Supply Curve -- Delivered Price to CA
Intermediate Term, CA Ban of MTBE
170.0
165.0
160.0
155.0
150.0
145.0
140.0
135.0
130.0
cents/gallon
0-10,000
10,001-20,000
20,001-30,000
30,001-40,000
40,001-50,000
50,001-60,000
60,001-70,000
70,001-80,000
80,001-90,000
90,001-100,000
barrels/day


Ethanol Supply Curve -- Delivered Price to Calfiornia
Long Term, CA Ban of MTBE
145.0
140.0
135.0
130.0
125.0
120.0
115.0
110.0
cents/gallon
0-10,000
10,001-20,000
20,001-30,000
30,001-40,000
40,001-50,000
50,001-60,000
60,001-70,000
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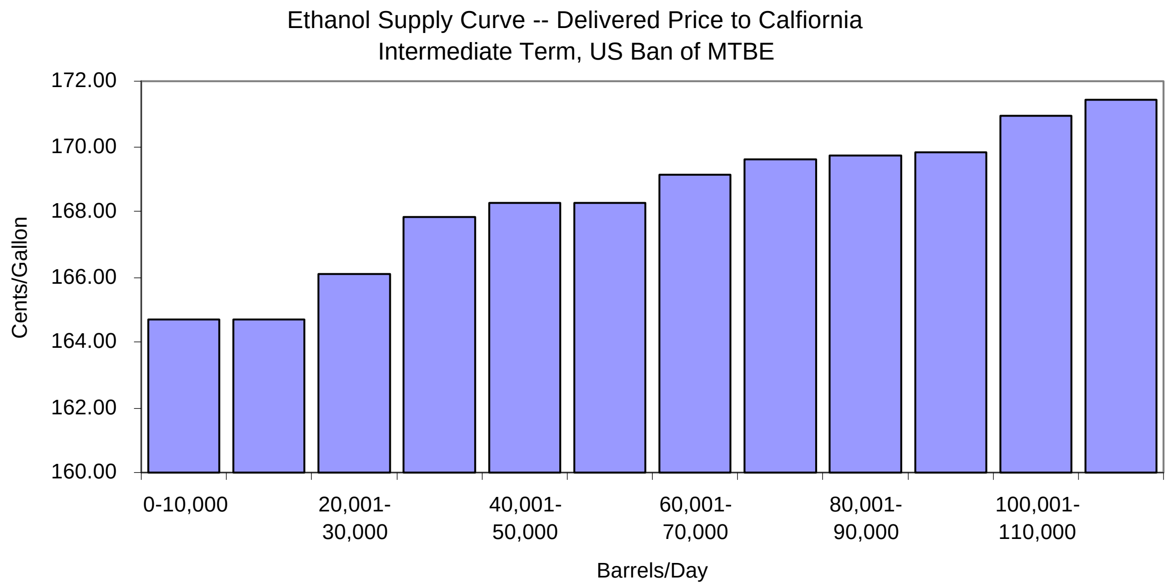
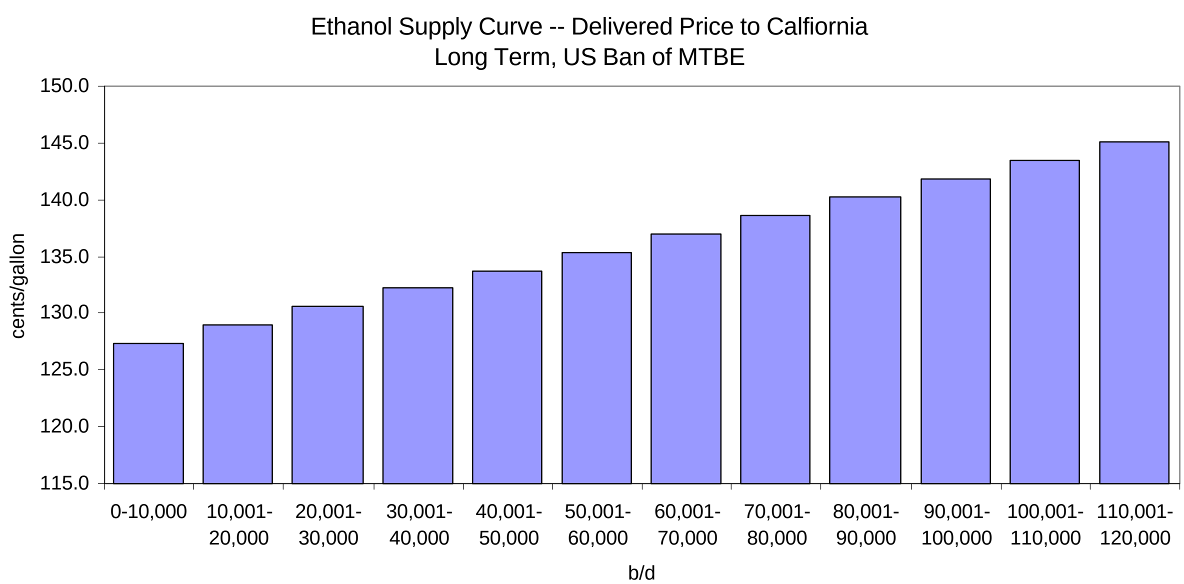
100,001-110,000
110,001-120,000
b/d


Ethanol Supply Curve -- Delivered Price to Calfiornia
Intermediate Term, US Ban of MTBE
172.00
170.00
168.00
166.00
164.00
162.00
160.00
Cents/Gallon
0-10,000
20,001-30,000
40,001-50,000
60,001-70,000
80,001-90,000
100,001-110,000
Barrels/Day


Ethanol Supply Curve -- Delivered Price to Calfiornia
Long Term, US Ban of MTBE
150.0
145.0
140.0
135.0
130.0
125.0
120.0
115.0
cents/gallon
0-10,000
10,001-20,000
20,001-30,000
30,001-40,000
40,001-50,000
50,001-60,000
60,001-70,000
70,001-80,000
80,001-90,000
90,001-100,000
100,001-110,000
110,001-120,000
b/d

Appendix I

Chapter 8

State Incentives, Initiatives and Programs
California Energy Commission
Alcohol Fuels Policy
Resolution # 80-0409-17

State Incentives and Initiatives

The following list summarizes selected information from a variety of databases available in the literature or on the Web. The principal source of information is Department of Energy's "Incentives and Laws – Guide to Alternative Fuel Vehicle Incentives and Laws", September 1998. Updates to this document can be found at **www.afdc.doe.gov**

Alabama – Offers incentives for conversion of fleet vehicles to alternatives up to $25,000 per project. Several utilities offer incentives for vehicle conversion to natural gas an on a case by case basis and fueling facility conversion as well. One private organization offers financing of the conversions at 9.5% interest.

Alaska – If gasoline contains 10% ethanol, it is exempt from the state fuel tax of 8 cents per gallon. This is equivalent to an 80 cent per gallon of ethanol produced subsidy. Incentives exist for the conversion to natural gas vehicles.

Arizona –Uses a combination of income tax reductions, vehicle license tax reductions and fuel tax reductions to encourage conversion for the purchase and use of alternative fuel vehicles. $1000 tax credit available for purchase of conversion to alternative fuels. $1000 available for small business or home refueling equipment. Grants of up to $100,000 available for construction of public AFV refueling sites. Tax credit for vehicle purchase becomes larger the lower the emission standard to which the vehicle is manufactured.

Arkansas - A $250,000 a year fund exists for the conversion of vehicles to alternative fuels. Ethanol and methanol vehicle conversion rebates of up to $1000 are available. The same rebate is also available for new purchases of manufacturer produced vehicles.
CNG has a preferred lower fuel tax rate relative to gasoline and other alternative fuel options.

Colorado – Has a tax credit and rebate program good through 2006 for natural gas and LPG vehicles. The program is not currently available to AFVs operating on alcohol and applies to public and private fleets only. Another program provides income tax credit for construction of alternative fuel facilities and partial payment of incremental costs of any vehicle (gasoline or alternative fuel) meeting LEV or better emissions standards. NEVC offers forgivable loans for installation of public E85 fueling facilities. Fuel tax exemptions for natural gas and LPG exist. Alcohol is not eligible for this fuel tax exemption.

Connecticut- the state offers a 50% state corporate tax credit for the cost of conversion of vehicles to LPG, CNG, LNG and electricity. Extends to fueling facility conversion as well. A 50% state investment tax credit is also available for vehicle conversions and fueling facility installations. No special provisions applicable to ethanol fuel. Also offers exemptions from the sales and use tax on the incremental cost difference between gasoline and AFV versions of OEM new vehicles. The state requires the use of clean alternative fuels in state vehicles under definition found in EPACT (1992).

Delaware – Applies PVEA funds to fund the incremental cost of AFV conversions or new vehicle purchases. Also applies the funds to train mechanics, develop infrastructure, educate fleet operators, and do vehicle emissions testing. No special tax provisions or exemptions for any fuels including ethanol.

District of Columbia – The District of Columbia has no special provisions or incentives for alternative fuels or AFVs.

Florida – Uses PVEA funds for incremental vehicle cost or conversion to alternative fuels- state vehicles only. $2.5 million low-interest revolving fund for AFVs in three counties is available. $1.1 million available in grants local governments in one Clean Cities coalition. City of Sunrise/Gas systems offers $300 worth of fuel for any individual or fleet signing up to use public natural gas fueling facilities. EVs exempt from sales tax from July 1, 1995 through June 30, 2000. State exempts local government AFVs from decal fee.

Georgia - $1500 tax credit is available for purchase or lease of all AFVs. Also gives AFVs access to HOV lanes for single occupancy vehicles. Educates legislators on the use of AFVs. Grants of up to $50,000 are available to local governments who demonstrate committed use of clean alternative fuels. Propane is exempt from the 4.5 cent a gallon excise tax when sold to consumer distributor. Flat tax credit of $1500 available to any EPACT defined alternative fuel vehicle (converted or new) that achieves EPA LEV or better emissions level. Can be carried over for three years on tax return. No special provisions for alcohol beyond what is mentioned above.

Hawaii – Gasoline blended with 10% biomass derived alcohol sold in the state is exempt from the 4 percent sales tax. This amounts to 30 to 50 cents per gallon subsidy of ethanol produced under 1998 gasoline prices. State income tax deductions available from \$2000 to \$50,000 for installations of clean fuel refueling facilities as defined in EPACT. Propane gets a two-thirds reduction in fuel tax relative to diesel fuel.

Idaho – Provides a fuel excise tax exemption for biofuels up to 21 cents per gallon at the 10 percent level. Applies to biodiesel and ethanol/gasoline blends. For ethanol this is equivalent to a \$2.10 subsidy per gallon of ethanol produced. Governor required by executive order that all state vehicles use E10 whenever possible effective in 1987.

Illinois – The state rebates 80% on the conversion or incremental cost of AFVs up to \$4000 per vehicle. An SEP grant for municipalities and state vehicles provides incremental costs of 50 AFVs. NEVC provides forgivable loans for the installation of E-85 fueling facilities. A \$20 a vehicle fleet user fee for fleets in excess of 10 vehicles funds the state Alternative Fuels Act. Funds go to ethanol research and the state AFV rebate program. Individuals can receive 80% of conversion or incremental costs of new AFVs if vehicle operates on ethanol or methanol at 80 volume percent or higher. 2% sales tax exemption exists for vehicles operating on E10 blends. This is a subsidy of 24 cents a gallon of ethanol used.
An Executive order in 1987 required all state vehicles to use E10. A 30% reduction in taxes on the proceeds of sales of gasohol made before July 1, 2003 exists. This returns to 100% of the taxes thereafter. Requires by 2000 that 70% of all state vehicles be capable of operating on clean alternative fuels. A state resolution (1997) encourages the federal government to cooperate in funding research intended to increase the use and production of ethanol. All vehicles leased by any state college or university must use E10 whenever possible. All public transportation authority districts with populations greater than 50,000 are required to use ethanol blends.

Indiana – Grants of \$2000 to \$10000 are available from the Small Business Energy Initiative Grant Program to help pay for the incremental costs of purchasing AFVs of for the installations costs of fueling facilities. NEVC provides forgivable loans for the installation of public E85 stations. Passed a law in 1996 providing a 10% gross income tax deduction for improvements to ethanol production facilities or soy diesel producing facilities. In 1993 a price preference of 10% was established for state and local government procurement of soy diesel. Provides some incentives for natural gas as well.

Iowa – The Iowa Energy Bank (state run) provides low interest energy loans for conversions and purchases of AFVs by state, local and non-profit entities. Department of Natural resources has funded the installation of public E-85 refueling sites. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. In 1988 the governor required that all state vehicles be fueled with E10 whenever practical. All vehicles owned or leased by city and county school districts and the Board of Directors of the community colleges must use E10. In 1998, the legislature extended the 1 cent a gallon sales tax exemption on for ethanol blended fuels through 2007. For E10 this amounts to a 10 cent per gallon of ethanol tax credit.

Kansas – Up to $2500 state tax credit for 50% of the cost of factory equipped AFV or individuals may take 5% of the total cost of the vehicle. For fleets of ten or more, an income tax can also be taken for on qualified AFV property, conversion equipment, and refueling property. After January 1, 1999 the tax credit for individuals drops to 40% of the cost of factory produced vehicles. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. A 14-cent per gasoline gallon equivalent tax break is available for CNG and LPG fuels. In 1992 the Governor required that all state agencies use alternative fuels in their fleets when cost effective.

Kentucky – Up to $1000 rebate is available from Western Kentucky Gas for conversion or incremental cost of new CNG vehicles. NO mandates and incentives for any other fuel exist. Some demonstrations underway.

Louisiana – A state income tax credit is available for 20% of the cost of converting a vehicle to alternative fuels or up to $1500 for 20% of the incremental cost of a new OEM vehicle. A 20 % income tax credit is also available for alternative fuel refueling stations. Utilities provide some incentives for natural gas conversion and use. Act 927 required that 80% of all state vehicles be converted to operate on alternative fuels by 1998. The law also forbade subsidies and incentives for the production of CNG, LPG, reformulated gasoline, methanol or ethanol. LPG was given a special alternative method for calculation of tax.

Maine – Provides a partial tax exemption for the purchase of clean fuel vehicles. Exemption applies to incremental cost of vehicle. Where no identical gasoline vehicle exists the exemption is 30% for internal combustion engines and 50% for electric and fuel cell vehicles. Department of Economic and Community Development provides loan guarantees to fleet operators for alternative fuel vehicle support. AFVs are exempt from sales and use tax, parking fees, and registration fees.

Maryland – An $800 to 2000 state tax credit is available to all owners of converted or purchased AFVs. Rebate is based on gross vehicle weight classification. These are eligible to fleets or individuals only if federal or state purchase requirements have already been achieved. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. EVs are given an experimental time-of-use rate of 2.512 cents per kw-hour. Provides a tax exemption of 1 cent per gasoline gallon equivalent for alternative fuels as defined by EPACT. Special incentives provided for natural gas and LPG. Sun Company will work with customers to establish fuel pricing. In 1993, Governor required that 20 to 25 % of new vehicle purchases be alternative fuel.

Massachusetts- Some incentives from utilities and private organizations for natural gas. Excise tax exemption for CNG and LPG of 11 cents per gasoline gallon equivalent, about half of the 21 cent per gallon state excise tax on gasoline. Neither provisions nor incentives for alcohol exist.

Michigan - $500 rebate for dedicated natural gas and $300 rebate for dual-fuel vehicle available from Consumers Power Company. There are no incentives for AFVs in Michigan (1998). Special electricity rate available from Detroit Edison. No mention of any alcohol related incentives.

Minnesota – Provides a 20-cent per gallon producer's incentive for fuel alcohol (ethanol) not to exceed $3 million per year per producer. Incentive remains effective for 10 years for each producer, but the program expires June 20, 2010. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. A State policy exists which states that it is in the states best long term interest to promote the development and market penetration of alternative fuels, and to develop additional markets for indigenous crop based fuels. Incentives are offered by utilities for natural gas vehicle conversion in the range of $250- $1000. E-85 fuel is taxed at 14.2 cents per gallon, methanol at $11.4 cents per gallon and gasoline at 20 cents per gallon.

Mississippi – Does not have incentives or mandates for AFVs. There are no fuel production incentives as well. One gas utility provides incentives for natural gas vehicles on a case by case basis.

Missouri – Offers a 20-cent per gallon production incentive of ethanol. There are no financial incentives offered for alternative fuel vehicles. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. An excise tax exemption of 2 cents per gallon exists for ethanol/gasoline blends which have10% or greater ethanol content. Missouri Appropriates funds yearly for the Missouri Ethanol Producer Incentive Fund. The Governor required that 50 % of all state owned vehicles operate on E10 by 2000.

Montana – In 1993 Montana created an ethanol producers tax credit of 30 cents per gallon. $6 million was appropriated that year and is available on a first come first served basis. A 50% income tax credit is available to individuals and companies for conversion costs of AFVs. $500 to 1000 maximum is available depending on the weight of the vehicle. State law requires that all state vehicles be fueled with ethanol gasoline blends when competitive with gasoline. Gas utilities provide additional incentives for natural gas vehicles.

Nebraska- has a 20-cent per gallon direct incentive for producers of ethanol with a cap of $25 million per plant. Created the Ethanol Development Act and a fund to research, develop and promote renewable agricultural ethyl alcohol. Offers no-cost and low cost loans for conversion of vehicles to alternative fuels. This applies to public and private vehicles. Funds are also available for installation of fueling facilities. In 1979 the Governor declared that all state vehicles fuel with E10 whenever practical.

Nevada – No incentives are offered statewide for the use of alternative fuels. A private fleet program exists in the Las Vegas area. Up to $3500 dollars is available after the entity puts up the first $1500 for the conversion to natural gas only. 90 % of all government fleet vehicles greater than 26,000 lbs. must convert to alternative fuels by the year 2000. Alternative fuels use is required.

New Hampshire – Has no incentives for alternative fuel use. Has no fuel production incentives.

New Jersey - Tax incentives exist for LPG and natural gas. PVEA funds ($1.5 million) are used by the Division of Energy to convert state vehicles to alternative fuels. While not specifically designating ethanol capable vehicles, New Jersey has an aggressive slate of projects and programs aimed at deploying AFVs consistent with EPACT requirements and utilizing DOE's Clean Cities Programs.

New Mexico - A partial exemption on fuel excise provides a 4 cents per gallon benefit for all alternative fuels ultimately. This exemption is being phased in over 6 years. At the same time, the tax on gasoline is scheduled to rise in 3 cent per gallon increments every two years until 2002 at which time 12 cents per gallon will have been added to the base gasoline tax of 16 cents per gallon. The Energy Conservation and Management Division of The Energy, Minerals and Natural Resources Department provides grant funds to reduce energy demand and consumption of petroleum products. Funds are provided on an annual basis and allocated through a competitive process for projects. Owners of AFVs can purchase an annual fuel tax decal for $15 per year in lieu of paying the per gallon road tax.

New York- The retail sales tax for the difference between the cost of a new converted AFV and the list price of a comparable vehicle. New York City established a program in 1991 to convert to alternative fuel or purchase 80% AFVs for the light duty non-emergency vehicle sector and 15 % in the transit bus sector. Generous credits are offered for EVs and Hybrid EVs though these are scheduled to be phased out in 2005. New York administers an AFV research and demonstration program through a competitive process. Utilities provide incentives to natural gas and EV vehicle owners and provide fueling facilities as well.

North Carolina- Since 1987 the state has provided a corporate and personal income tax credit for construction of certain new ethanol fuel plants for the state. Promotional rates for electricity and natural gas are also offered by two utilities. Alternative fuel vehicle projects are supported on a case-by-case basis.

North Dakota- the governor has ordered that all state vehicles must be must be fueled with E10 when possible. The North Dakota State Bank provides loan guarantees for construction of ethanol production facilities in the state. In 1995, $3,657,000 was appropriated for an incentive of 40 cents per gallon for agricultural fuel produced and sold in North Dakota. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. Incentives for natural gas vehicle conversion are offered by one utility. IN 1995 limits were placed on what any single company could receive in ethanol subsidies.

Ohio - The state provides a 1-cent per gallon income tax credit for sale of E10 with a maximum of $15 million per year. In 1990 the governor directed fleets in three agencies to use E10 whenever possible. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. Two utilities provide fueling facilities for natural gas users and some forms of assistance. No vehicle conversion incentives are provided.

Oklahoma- Provides a 50% income tax credit for vehicle conversions to alternative fuels and 10% of the total vehicle cost up to $1500 to individuals who buy an AFV. An income tax credit is also available for installing refueling equipment for AFVs. A private loan program exists with a 3 % interest rate for conversion of private fleets to alternative fuels. 3 years are allowed for payback. All alternative fuels as defined by EPACT are eligible. CNG, LPG and LNG are exempt from fuel excise tax and pay a flat yearly fee instead. Ethanol and methanol receive no special fuel tax consideration.

Oregon - Offers a business energy tax credit of 35% available for vehicle conversions and fueling stations. All natural gas utilities will buy back the 35% credit at present value for purchase of an AFV.

Pennsylvania- Incentive grants are provided for the purchase of AFVs and fueling facilities in accordance with EPACT definitions. The funding varies from 40(1998) to 20 (2001 and on) percent and is paid from gross receipts taxes paid by some Pennsylvania utilities. $3 to 4 million is available each funding cycle and some distribution rules apply. Gas and electric utilities provide incentives for EVs and natural gas vehicles.

Rhode Island - Taxpayers receive a 50% credit for costs of installing fueling facilities and 50% for the cost of converting a car to use alternative fuels, or 50% of the incremental cost of an OEM vehicle. Rebates and incentives are providing by utilities for natural gas vehicles on a case-by-case basis.

South Carolina - Does not offer any incentives for AFVs. A promotional gas rate for natural gas is available for AFV users.

South Dakota - Offers reduced fuel taxes for AFVs. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. Incentives for natural gas vehicle conversions are available.

Tennessee - No incentives provided for alcohol fuels. Some incentives for natural gas exist as provided by one gas utility.

Texas - Incentives provided for natural gas and LPG vehicles and fueling facilities. Utilities are involved in this process. 50 % of state fleet vehicles required to operate on alternative fuels by 1996. Local fleet requirements as well. A 1995 law allows the Texas Public Finance Authority to sell bonds up to $50 million to finance loans for school districts, local mass transit authorities and state agencies to convert vehicles to alt fuels, purchase new vehicles and install facilities. CNG and LNG pay an annual sticker permit fee in lieu of fuel tax.

Utah - Tax credit and loan programs exist for AFV purchases. 20% tax credit up to $400 offered for each new AFV registered and a tax credit up to $400 for fueling facilities for CNG, LPG, and LNG. CNG and electricity are exempt from franchise taxes imposed by municipal and county governments.

Vermont - No state incentives offered. One gas utility offers incentives for natural gas vehicle conversions on a case-by -case basis.

Virginia - Provides no-charge licensing for AFVs and exemption from HOV lane requirements. Provides a 10% tax credit, a 1.5- percent sales tax reduction and an AFV fuel tax reduction of 6 cents per gasoline gallon equivalent. The state provides a $700 tax credit to a corporation that creates a full time job related to the manufacturing of AFVs or AFV components or job related to converting vehicles to run on alternative fuels. A revolving fund provides grants to local governments and state agencies for conversion of publicly owned vehicles from gasoline and diesel to alternative fuels.

Washington - Offers fuel tax reductions to LPG and natural gas vehicles and infrastructure development for compressed natural gas from PVEA funds. Light duty vehicles operating on LPG and natural gas pay an $ 85 annual fee in lieu of fuel excise taxes. No special treatment for alcohol fuels.

West Virginia - $3750 to 50,000 in tax credits for purchase and conversion of alt fuel vehicles (up to 26,000 lbs. and more). Tax credit available on the incremental cost of AFVs. Grants for conversion for local governments from the state with a 50% local match of funds. CNG, electricity and methanol are eligible fuels. Tax credit good for all alternative fuels including alcohol and alcohol derived liquids.

Wisconsin - Competitive grants available to municipalities. $4500 to $15000(trucks, vans or buses). Uses CMAQ funding. Utilities offer electric and natural gas incentives and rebates. Governor has a goal of 2000 vehicles purchased by 2000 thus exceeding

EPACT requirements. State has initiated private-public partnerships to stimulate ethanol, CNG, propane, methanol, and biodiesel fuels and infrastructure.

Wyoming - Has no vehicle conversion incentives. Use PVEA funds to convert state vehicles to alternative fuels. Provides a 4-cent per gallon fuel tax exemption for E10 use. This is equivalent to a 40 cent per gallon subsidy. and extends to June of 2000. Issues credit vouchers to ethanol producers which are redeemable by gasoline wholesalers with tax liability (E10) or gasoline.

CALIFORNIA ENERGY COMMISSION

RESOLUTION

ALCOHOL FUELS POLICY

WHEREAS, California and the U.S. have become increasingly dependent on imported petroleum products and subject to the threat of economic and social disruption from the manipulation of petroleum supplies and prices; and

WHEREAS, the transportation sector is almost totally dependent on petroleum products primarily in the form of gasoline, such that more than half of the petroleum used in the State is used in the transportation sector; and

WHEREAS, the Legislature called for the development of an alcohol fuels program as a means of reducing reliance on imported petroleum products for transportation; and

WHEREAS, the Energy Commission is participating in such a program and has (1) conducted field tests of autos using alcohol and gasoline fuel blends, (2) initiated feasibility studies leading to financial support for the construction of two or more commercial facilities to produce at least two million gallons per year of alcohol fuel from agricultural wastes and surplus, and (3) initiated a program to field test over 100 vehicles fueled by straight alcohol fuels and capable of mass production for use in state and local captive fleets; and

WHEREAS, Commission tests and other studies have demonstrated that:

(1) gasoline/alcohol fuel blends can be used without significant changes in fuel efficiency or exhaust emissions in existing motor vehicles,

(2) blended fuels cause substantial increases in fuel system evaporative emissions,

(3) additional research is necessary to determine the extent to which evaporative emissions from blended fuels can be avoided,

(4) straight alcohol fuels used in properly modified motor vehicles increase thermal efficiency, substantially decrease exhaust emissions for all regulated pollutants, and eliminate evaporative emissions of regulated pollutants that occur with either gasoline or gasoline/alcohol blends; and

WHEREAS, the displacement of gasoline with pure alcohol fuels can occur with the least difficulty in captive fleets, including fleets operated by state and local governments, and can provide reliable and economic fuels for essential government transportation services, thus insulating these services from foreign manipulation of petroleum prices and supplies.

IT IS THEREFORE RESOEVED, THAT:

(1) The California Energy Commission supports the vigorous development of an alcohol fuels industry in California.

(2) For transportation fuels, the major emphasis should be placed on the use of straight alcohol fuels; and as a first step, the state should encourage the use of such fuels in fleet vehicles.

(3) The Commission supports the limited near-term use of alcohol/gasoline blends consistent with California's air quality goals.

(4) Future expansion of alcohol/gasoline blend fuels must depend on development of satisfactory techniques to substantially reduce or eliminate the evaporative emissions attendant with the use of such fuels.

IT IS FURTHER RESOLVED THAT the California Energy Commission shall continue to implement a program to develop alcohol fuels in California, including but not limited to the following actions:

(1) Identifying means to improve efficiency of alcohol conversion and its use in vehicle engines.

(2) Creating markets for alcohol fuels in California by encouraging utility use of alcohol as a boiler and turbine fuel and by demonstrating the advantages of using alcohol fuels in captive fleets.

(3) Developing and recommending appropriate incentives for alcohol use.

(4) Promoting the construction of alcohol production facilities by providing engineering feasibility analysis, loans and other financial incentives for potential producers and marketers.

(5) Supporting programs that will enable state and local governments and private industries to convert captive fleets to use of straight alcohol fuels, and vehicle manufacturers to offer mass produced vehicles capable of using such fuels.

(6) Securing available federal funds for additional development of an alcohol fuels industry in California.

(7) Determining the most appropriate and efficient sources and conversion processes for alcohol fuels from natural gas, coal, and biomass alternatives.

(8) Developing quantitative goals for production and utilization of alcohol fuels in California.

DATED: April 9, 1980

RUSSELL L. SCHWEICKART,
Chairman

Appendix J

Peer Review Group List

Appendix J

External Peer Review Group
For Ethanol/Biomass Report

FEDERAL GOVERNMENT
John Ferrell – United States Department of Energy
Dr. Robin Graham – Oak Ridge National Laboratory
Larry Baxter – SANDIA
Hosein Shapaouri – United States Department of Agriculture

STATE GOVERNMENT
Martha Gildart – California Integrated Waste Management Board
Steven Shaffer – California Department of Food and Agriculture
Dean Simeroth – California Air Resources Board

LOCAL GOVERNMENT
Kay Martin – County of Ventura

ACADEMIC/UNIVERSITY/OTHER
Esteban Chornet – University of Sherbrooke (Canada)

PRIVATE INDUSTRY & ASSOCIATIONS
Kent Hoekman – Chevron
Bob Benson – TEMBEC Chemical Products
Carol Werner – Environment and Energy Study Institute
Bob Dinneen – Renewable Fuels Association
Daryl E. Harms – MASADA
Doug G. MacKenzie – Pacific Rim Ethanol Corporation
David Morris – Institute for Local Self Reliance

Appendix K

Ethanol Information from the

Governors' Ethanol Coalition

Appendix K

California Energy Commission Request for Information From the Governors' Ethanol Coalition July 29, 1999

1. Data on planned biomass-based plants in the Midwest or multi-feedstock processing plants.

A great deal of work has been done to commercialize ethanol production from corn stover and other biomass available in the Midwest. Currently, however, such production is not economic when compared to ethanol production from corn. There are plants which produce ethanol from a variety of grain-based feedstocks, e.g.., corn and milo, because of the similarities of processing. Georgia Pacific Corporation, in Washington State, produces ethanol from wood and fiber waste. Simplot, in Idaho, produces ethanol from potato waste. Parallel Products in California, produces ethanol from a variety of beverage and food wastes. BC International has begun construction on a biomass-ethanol facility in Jennings, Louisiana that will utilize rice hulls and bagasse. Masada Resource Group has proposed building an ethanol plant in New York that utilizes the cellulose portion of municipal solid waste. There are also several projects underway in California that would utilize rice straw to produce ethanol. In Nebraska, two companies have initiated detailed engineering analyses of ethanol plant modifications necessary to accommodate conversion of biomass in conjunction with current grain processing.

2. Facility financing and a description of how early plants have been financed and how new ones will be financed.

More than $5 billion has been invested to build the national ethanol industry. Facility financing has always been based on market opportunities. In the current climate, capital has been constrained by the questions regarding MTBE, and whether the proposed bans on MTBE will be sustained, or whether MTBE will continue to be used in California and other states despite its water contamination problems.

In the future, the financial community, as it would with any production industry, will need some assurance a market exists before financing new facilities. Several companies producing ethanol today have investment capital of their own, which could be used to finance production expansion. There could also be continued expansion of farmer-owned cooperatives, in which farmers invest their own savings and pledge a percentage of their crops to an ethanol production facility. The farmer owned cooperative model has worked quite well in the Midwest. In fact, the large majority of ethanol industry expansion over the past ten years has been by farmer-owned cooperatives. As always, investment capital will flow with the assurance of increased market demand.

3. Production costs and prospects for technical advancements for corn to ethanol.

Over the past decade, ethanol production costs have continued to drop. The most significant gains have been made in energy costs and production efficiencies. But real gains are also now being made in transforming the value of fermentation streams into higher value products. A proposed ethanol pilot plant in southern Illinois could be used to reduce production costs further by testing new processes and feedstocks, and providing valuable information to the ethanol industry.

4. Prospects for ethanol beyond the oxygenate/gasoline market.

Other potential uses for fuel grade ethanol and a brief description for the prospects of that use are as follows:

E85/Flex-fuel Vehicles: Current auto manufacturer offerings of flex-fuel vehicles that can operate on E85 include the Ford Taurus, all Ford Rangers with the 3.0L engine (and its Mazda twin) and all Chrysler/Dodge/Plymouth minivans with the 3.3L engine. In addition, Ford plans to expand its FFV offerings to include the Windstar minivan, and GM has announced that all of its Chevrolet S-10/GMC Sonoma pickups of certain engine configurations will be flex-fuel capable beginning with the 2000 model year.

These offerings should result in the number of vehicles capable of operating on E8S increasing by 300-400 thousand vehicles per year.

Despite this large number of vehicles projected, growth for E8S usage is low due to limited infrastructure for fuel delivery (currently fewer than 60 retail outlets) and the cost of E8S which on a miles traveled basis is currently more expensive than gasoline due to E85's lower energy content. The U.S. Postal Service will receive delivery on 10,000 flex-fuel service vehicles this fall, and has indicated it is likely to exercise an option to purchase an additional 10,000. The Postal Service and ethanol industry are working to locate these vehicles in significant numbers to spur private fuel infrastructure development. The Department of Energy has instituted a "model cities" program that concentrates resources on developing a significant private E8S fuel infrastructure in Minneapolis, Chicago and Denver.

Fuel Cell/Reformers: Ethanol could be used with a reformer to power fuel cells. Such a reformer has already been developed. However, thus far the auto manufacturers' programs have focused on fuels other than ethanol.

Oxydiesel: There is some potential to blend ethanol with diesel, but this is in the preliminary demonstration mode and the potential, if any, cannot yet be predicted.

EIBE: Ethanol could be processed into ethyl tertiary butyl ether (ETBIS) or other ethers. However at current ethanol/methanol cost differentials, ETBE production is not competitive with MTBE production and is not likely to be so in the near term.

5. Cost of transporting ethanol from Nebraska and the Midwest to California.

As noted in a study prepared by Downstream Alternatives, Inc., "The Use of Ethanol in California Clean Burning Gasoline-Ethanol Supply/Demand and Logistics," transportation costs from major Midwest producers to California range from 14 to 17 cents per gallon for rail with marine cargoes falling in the same range when transportation to a New Orleans staging area are included. From central Nebraska the transportation costs range from 12 to 14 cents per gallon.

6. Ideas on how to solve vapor pressure problems with low-alcohol blends.

The most effective means of addressing the "vapor pressure problems" associated with ethanol use would be to recognize the contribution of carbon monoxide reductions on urban ozone and allow those reductions to offset, to some degree, thc increased evaporative VOC emissions which result. Such an approach would be scientifically sound and would mitigate, to some degree, the costs refiners currently have in utilizing ethanol in California's Cleaner Burning Gasoline program.

In the absence of an offset for carbon monoxide reductions, there arc two approaches to this problem 1) adjust thc basic gasoline, and 2) develop a fuel additive or component that reduces ethanol's blending vapor pressure.

Base Gasoline Adjustment: Because ethanol slightly increases gasoline volatility, refiners would have to make adjustments to their base gasolines in order to accommodate ethanol. The extent of thc changes and the cost of such changes would vary by refinery. A report entitled "*Analysis* a*nd Refinery Implicatons of Ethanol-Based RFG Blends under the Complex Model-Phase 1I;* by Pace Consultants, concluded that a relatively complex refinery could make the necessary adjustments in gasoline blendstock to meet more stringent volatility requirements at a relatively modest cost ($0.07/gal) in some situations.

Develop additive or component to reduce ethanol's blending vapor pressure: In combination with petroleum derived gasoline, ethanol forms a non-ideal mixture. This means that the properties and behavior of the mixture differ significantly from what would be predicted from simple linear calculations of the properties. Ethanol forms an azeotrope with pentane and hexane type molecules in gasoline. The azeotopic effect of the ethanol is that the mixure boils at a lower temperature than would normally be expected. The presence of water in the gasoline-ethanol blends can also have a small affect on the volatiliy and azeotroping effects.

Short of modifying the base gasoline, the only other approach would be to develop an additive or component that, when added in small quantities, would break the azeotrope or dramatically reduce its affect. Research is currently underway to identify additives that when added in small quantities (i.e. less than 1%) would affect the azeotrope. Development of such a fuel ingredient will require extensive effort.

Some work has shown that heavier ethers (e.g., ETBE, TAME) and heavier alcohols (e.g., TBA, IBA) can be used as cosolvents and will reduce the blending vapor pressure of ethanol. However, the required quantities of the cosolvant in the blend needs to be nearly equal to the ethanol volume. Since such blends are limited to 2.7 wt.% oxygen, under the substantially similar rule this equates to a bind containing ~ 5% cosolvent, 5% ethanol and 90% gasoline.

Unfortunately, supplies of these potential cosolvents are limited, and the costs are high.

7. **What do you see as the most significant economic, technical, regulatory and environmental challenges facing Midwest ethanol producers from expanding exports to California?**

Economic: Providing that net back prices to the plants are at least equal to prices for other markets, there are no economic obstacles.

Technical: The most significant technical challenge is on the refinery side where it would be necessary (under the existing regulatory scheme) to produce a sub RVP RBOB. This necessitates removal of pentanes and probable addition of alkylate. There are no other technical obstacles that have not been routinely solved in other ethanol markets.

Regulatory: The primaly regulatory obstacle is that the current predictive model does not fully acknowledge ethanol's benefits with regards to CO reduction and the contribution of CO to ozone formation.

Environmental: See regulatory above.

8. **Information on water absorption and fuel from transporting ethanol.**

Ethanol (200 proof) can absorb ~ 5°/ water at 60 tegrees F. However, the industry standard, ASTM D 4806-98 Standard Specification for Dated Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel," permits only 1 v% water maximum. All producers routinely meet this standard at delivery, indicating that the combination of water present at thc end of manufacturing (typically 0.65 v%) and the remaining small amount absorbed in transit do not exceed 1 v%.

9. **An inventory of current U.S. ethanol producers, with production facilities locations, capacities, process descriptions and feedstocks.**

U.S. ETHANOL PRODUCTION CAPACITY

Current - Under Construction – Proposed

Current Production Capacity				
COMPANY	**LOCATION**		**FEEDSTOCK**	**MMPY**
A.E. Staley	Loudon	TN	Corn	45
AGP*	Hastngs	NE	Corn	45
Agri-Energy*	Luverne	MN	Corn	15
Alchem	Grafton	ND	Corn	10.5
Al-Corn*	Claremont	MN	Corn	15
Archer Daniels Midland (total capacity)	Decatur	IL	Corn	750
	Peroria	IL	Corn	
	Cedar Rapids	IA	Corn	
	Clinton	IA	Corn	
	Walhalla	ND	Corn/barley	
Broin Enterprises	Scotland	SD	Corn	7
Cargill (total capacity)	Blair	NE	Corn	100
	Eddyville	IA	Corn	
Central Minnesota*	Little Falls	MN	Corn	15
Chief Ethanol	Hastings	NE	Corn	40
Chippewa Valley Ethanol*	Benson	MN	Corn	17
Corn Plus*	Winnebago	MN	Corn	17.5
Eco Products of Plover	Plover	WI	Whey/potato waste	4
ESE Alcohol	Leoti	KS	Corn/milo	1.1
Ethanol2000*	Bingham Lake	MN	Corn	15
Exol, Inc.*	Albert Lea	MN	Corn	15
Georgia-Pacific	Bellingham	WA	Paper waste	7
Golden Cheese*	Corona	CA	Whey	2.8
Grain Processing Corp.	Muscatine	IA	Corn	10
Heartland Corn Products*	Winthrop	MN	Corn	10
Heartland Grain Fuel*	Aberdeen	SD	Corn	8
High Plains Corporation	York	NE	Corn/Milo	68
	Colwich	KS		
	Portales	NM		
J.R. Simplot	Caldwell	ID	Potato waste	3
	Burley	ID	Potato waste	3
Jonton Alcohol	Edinburg	TX	Corn	1.2
Kraft, Inc.	Melrose	MN	Whey	3
Manildra Ethanol	Hamburg	IA	Corn/milo/wheat starch	7
Merrick/Coors	Golden	CO	Brewery waste	1.5
Midwest Grain (total capacity)	Pekin	IL	Corn/wheat starch	108
	Atchison	KS		
Minnesota Clean Fuels (MN report says .5)	Dundas	MN	Waste sucrose	1.5
Minnesota Corn Processors* (total capacity)	Columbus	NE	Corn	110
	Marshall	MN	Corn	
Minnesota Energy*	Buffalo Lake	MN	Corn	12
Morris Ag Energy	Morris	MN	Corn	8
Nebraska Energy (Williams Energy)	Aurora	NE	Corn	
New Energy Corp.	South Bend	IN	Corn	85
Pabst Brewing	Olympia	WA	Brewery waste	.7
Parallel Products	Louisville	KY	Beverage waste	7
	Bartow	FL	Beverage waste	5
	R. Cucamonga	CA	Beverage waste	3
Pro-Corn*	Preston	MN	Corn	15
Reeve Agri-Energy	Garden City	KS	Corn/milo	10
Williams Energy Services	Pekin	IL	Corn	130
Wyoming Ethanol	Torrington	WY	Corn	5
Subtotal Current Production Capacity				**1,737**

Plants Under Construction				
COMPANY	**LOCATION**		**FEEDSTOCK**	**MMPY**
Adkins Energy*	Lena	IL	Corn	30
BC International	Jennings	LA	Bagasse/rice hulls	20
Nebraska Nutrients	Sutherland	NE	Corn	15
NE Missouri Grain Processors*	Macon	MO	Corn	15
Heartland Corn Products*	Huron	SD	Corn	12
Sunrise Energy	Blairstown	IA	Corn	5
Subtotal Under Construction Capacity (by 2000)				**97**

Proposed Plants				
COMPANY	**LOCATION**		**FEEDSTOCK**	**MMPY**
Golden Triangle*	St. Joseph	MO	Corn	25
American Agri—Technology Corporation	Great Falls	MT	Wheat/Barley	30
Lower Caskaskia Economic Devp. Board	Lower Caskaskia	IL	Corn	100
Quincy Library Group	NE Region	CA	Forest Residues	15
BC International (Sacramento Valley)	Gridley	CA	Rice Straw	30
Arkenol*	Mission Viejo	CA	Rice Straw	8
MASADA	Middletown	NY	Municipal Solid Waste	6.6
Sustainable Energy Corp.	Central Region	OR	Wood Waste	30
Pacific Rim Ethanol Corp.	Moses Lake	WA	Grain	40
Pacific Rim Ethanol Corp.	Longview	WA	Grain	40
Schmidt Brewery	St. Paul	MN	Beer Waste	5
GreenLeaf	Platte	SD	Corn	15
Pratte Project	Pratte	KS	Corn/milo	15
Iowa #1	Central Iowa	IA	Corn	15
Iowa #2	Central Iowa	IA	Corn	15
SIRS	Central Missouri	MO	Corn	30
N/a	Black Hills	SD	Forest Residues	12
Subtotal Proposed Capacity (by 2001)				432
TOTAL CURRENT AND PROJECTED ETHANOL PRODUCTION CAPACITY				**2,266**

MMPY= million gallons per year
*Cooperatives

Source: Bryan & Bryan, Inc.

10. Historical data on U.S. ethanol production costs trends with identification factors that have affected these trends.

The USDA has been asked to provide this information. A brief overview of corn conversion costs,
Ethanol Production From Corn, is enclosed.

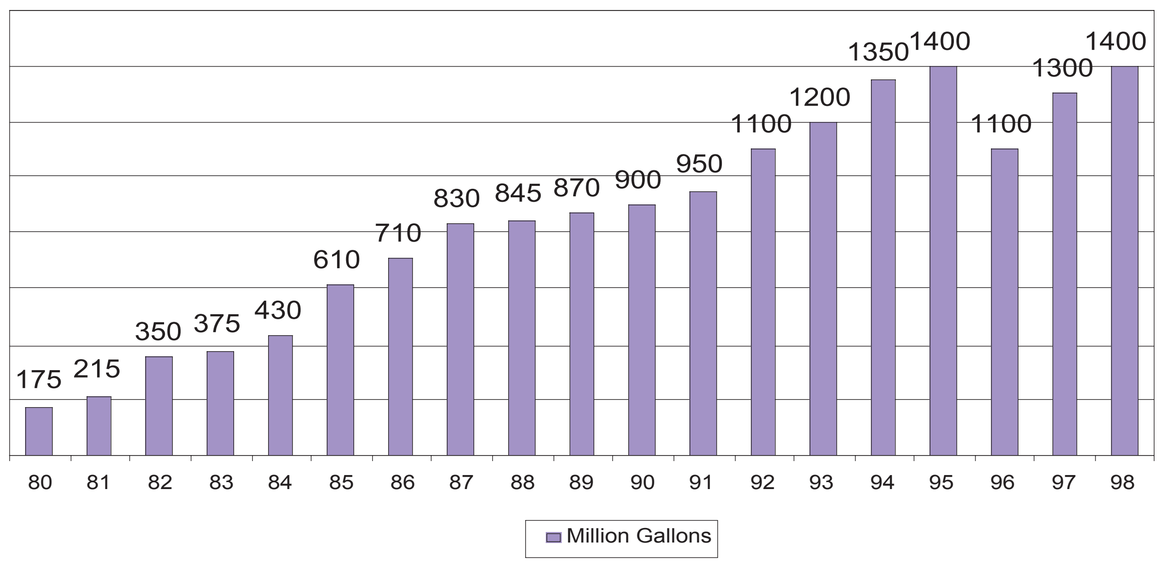
11. Listing of known scheduled/planned ethanol production capacity additions in the U.S.

See number nine, above.

12. Historical U.S. ethanol fuel consumption, including distribution by state.

The following is a chart of historical ethanol production/consumption

U.S. Fuel Ethanol Production



ETHANOL USE BY STATE

State	Ethanol Blends as % of '96 Gasoline Sales		State	Ethanol Blends as % of '96 Gasoline Sales
Alabama	1.96		Nebraska	23.04
Alaska	48.07		Nevada	--
Arizona	15.57		New Hamphire	--
Arkansas	0.02		New Jersey	3.92
California	12.59		New Mexico	21.68
Colorado	44.95		New York	5.07
Connecticut	2.66		North Carolina	9.84
Delaware	--		North Dakota	14.80
Florida	0.13		Ohio	18.68
Georgia	--		Oklahoma	--
Hawaii	--		Oregon	--
Idaho	--		Pennsylvania	13.10
Illinois	30.10		Rhode Island	--
Indiana	17.28		South Carolina	--
Iowa	34.28		South Dakota	37.26
Kansas	2.32		Tennessee	0.11
Kentucky	3.28		Texas	2.14
Louisiana	0.94		Utah	1.11
Maine	--		Vermont	--
Maryland	1.56		Virginia	13.81
Massachusetts	--		Washington	6.57
Michigan	4.94		West Virginia	0.29
Minnesota	66.85		Wisconsin	25.58
Mississippi	0.18		Wyoming	6.42
Missouri	4.61			
Montana	--		**U.S. Totals**	**9.82**

Source: Office of Highway Information

13. Historical summary of U.S. ethanol fuel market pricing, distinguishing effects of federal and state
tax incentives.

This issue is covered, in part, in the enclosed analysis by the Downtown Alternatives, Inc., entitled *"Ethanol Supply, Demand, and Logistics, California and Other RFG Markets*. A summary of ethanol tax incentives by state is also enclosed, entitled "*State Motor Fuel Taxation and Regulation* from the Oxy-Fuel News, dated July 19, 1999.

14. Projections of future overall U.S. ethanol fuel demand (with and without contingencies re:
oxygenated fuel requirements, MTBE replacement, etc.).

The USDA Office of Energy Policy and New Uses has completed all analysis, "An MTBE Phase-Out Scenario," which concludes ethanol can totally replace MTBE over a short period of time and maintain existing markets. To do this, domestic ethanol capacity would have to essentially double over the next five years. That is absolutely possible.

15. Status and outlook regarding use of ethanol (or E-85) as a neat fuel in the U.S. (Including both vehicles and fuels infrastructure).

See item 4 above.

16. What are the local permitting and siting requirements/timetables for building ethanol production facilities in the Midwest?

Ethanol production facilities are largely modular. Expansions can be done very quickly by simply adding new equipment to existing production streams. With permitting requirements for such expansions, it would take approximately one year to put on new capacity. Capacity will easily meet demand with current three and one half year phase in.

17. What are the direct and indirect tax base impacts from the ethanol industry in the Midwest?

A 1997 report completed for the Midwestern Governors' Conference demonstrates the positive impact of the domestic ethanol industry on the U.S. economy, including creating jobs, stimulating tremendous economic activity, and reducing our trade imbalance. "*The Economic Impact of the Demand for Ethanol,"* prepared by Dr. Michael Evans, Kellogg School of Management, Northwestern University, concludes that the ethanol industry:

- increases net farm income more than $4.5 billion;
- boosts total employment by 195,200 jobs;
- improves the balance of trade by over $2 billion;
- adds over $450 million to state tax receipts; and
- results in a net federal budget savings of over $3.5 billion.

A related economic analysis by Iowa State University economists entitled "*Effects of an Oxygen Requirement for Fuel in Midwest Ethanol Markets and Local Economies."*

18. What activities are being pursued to reduce market uncertainty and investment risk for feedstock production, collection, distribution, conversion and ethanol production?

As noted above, the biggest issue is future ethanol demand. Supply and production are not issues. The longer uncertainty is in the market place, the longer it will take to put in capacity. Thc U.S. ethanol industry needs a clear signal from California there will be certain significant demand. Unfortunately, the current signal from refiners and regulators in the state is that there is “no demand.”

Wet vs. Dry Milling

The discussion of wet versus dry milling usually comes up whenever ethanol production is discussed and many ask the question without any understanding of the differences between the processes. To put it most simply, a wet mill soaks the corn, enabling separation of some of the kernel's components and the separated starch is then converted to sugar (saccharification) and fermented and distilled into 200 proof ethanol. The pure stream of starch can also be sold as food or industrial grade starch, processed into syrup, sweeteners or a variety of high value products. Wet mills cost more than twice as much per bushel of grind to build as dry mills, but the resulting variety of products can be considerably more valuable.

A dry mill grinds the corn into a meal, adds water, saccharifies, ferments and distills the entire mash, creating two products, ethanol and Dried Distillers Grain with solubles (DDGS). Modern technology today has greatly increased the efficiency of small dry mills to the point where they are very competitive with large wet mills for the production of ethanol. A dry mill eliminates the expensive process of creating the pure starch stream before fermentation. In terms of relative profitability, the relative prices of gluten feed, gluten mean, corn oil, starch and DDGs determine which of the two processes is the least expensive for producing ethanol.

ETHANOL PRODUCTION FROM CORN

These two spreadsheets are actual market prices for corn and some of the products that result from value-added processing on two random dates during 1994. Both the largest (October) and smallest (March) processing margins for the past five years occurred in 1994.

The gross operating margin to make ethanol in a Dry Mill, for this particular day in March was $1.39 per bushel of corn processed. ($4.15 minus $2.76)

The gross operating margin to make ethanol in a Dry Mill, for this particular day in October was $2.67 per bushel of corn processed. ($4.60 minus $1.93)

The difference from March to October in 1994 was $1.28 per bushel.

This example proves the difficulty of estimating annual operating profits for the new ethanol plants proposed in Minnesota! This potential variability in process can also affect wet mill profits and is a major reason for the difficulty in accessing long term financing. The 20¢ producer payment provides a stable cash flow to new plants which decreases risk for lenders.

October 1994 Prices

Products	Corn	Value-Added				
	Raw Commodity	Wet-Milling				Dry-Milling
		Starch & Products	Ethanol & Products	Sweeteners & Products		Ethanol & DDG
				Corn Syrup	HFCS	
Corn	$1.93					
Corn Oil		$0.41	$0.41	$0.41	$0.41	
Gluten Feed		$0.44	$0.44	$0.44	$0.44	
Gluten Meal		$0.29	$0.29	$0.29	$0.29	
Starch		$3.71				
Ethanol			$3.34			$3.52
Corn Syrup				$4.86		
HFCS					$6.70	
DDG						$1.08
Total Value	$1.93	$4.85	$4.48	$6.00	$7.84	$4.60

Computation based on the following:

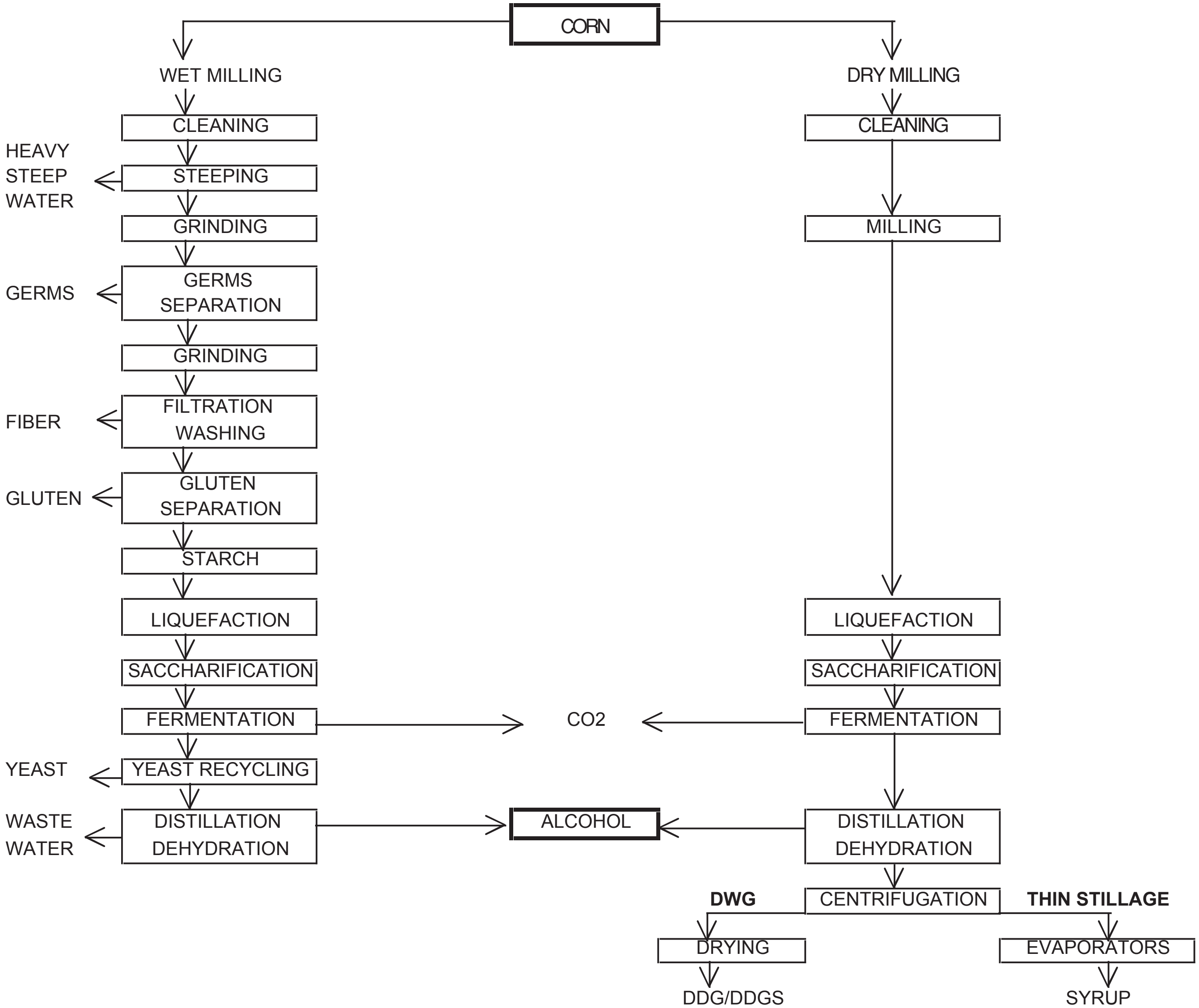
Corn: $1,929/bu. cash price (Wall Street Journal)
Corn oil: 1.55 lb./bu, $0.27/lb. (Wall Street Journal)
Gluten feed: 13.5 lb./bu, $86/ton, Illinois (USDA Market News)
Gluten meal: 2.65 lb./bu.$226.9/ton, Illinois (USDA Market News)
Starch: 31.5 lb./bu., $0.12/lb. (USDA, ERS)
Ethanol: 2.45 (wet-mill)/2.58 (dry-mill) ga./bu., $1.35/ga. (Mpls/St. Paul market, CPC)
Corn Syrup: 40 lb./bu., $0.12/lb. (Milling and Baking News)
HFCS: 33.33 lb./bu., 55% HFCS (dry weight), $0.20/lb. (Milling and Baking News)
DDG: 18 lb./bu., $120.5/ton (USDA, Grain & Feed Market News)

March 1994 Prices

Products	Corn	Value-Added				
	Raw Commodity	Wet-Milling				Dry-Milling
		Starch & Products	Ethanol & Products	Sweeteners & Products		Ethanol & DDG
				Corn Syrup	HFCS	
Corn	$2.75					
Corn Oil		$0.44	$0.44	$0.44	$0.44	
Gluten Feed		$0.44	$0.44	$0.44	$0.44	
Gluten Meal		$0.36	$0.36	$0.36	$0.36	
Starch		$3.62				
Ethanol			$2.92			$3.07
Corn Syrup				$4.96		
HFCS					$6.56	
DDG						$1.08
Total Value	$1.93	$4.86	$4.16	$6.20	$7.80	$4.15

Computation based on the following:

Corn: $2.76/bu. cash price (Wall Street Journal, March 25, 1994)
Corn oil: 1.55 lb./bu, $0.29/lb. (Wall Street Journal, March 25, 1994)
Gluten feed: 13.5 lb./bu, $88.5/ton, Illinois (Wall Street Journal, March 25, 1994)
Gluten meal: 2.65 lb./bu.$287.5/ton, Illinois (USDA Market News)
Starch: 31.5 lb./bu., $0.115/lb. (Industry sources))
Ethanol: 2.45 (wet-mill)/2.58 (dry-mill) ga./bu., $1.19/ga. (Mpls/St. Paul market, March 25, 1994, CPC)
Corn Syrup: 40 lb./bu., $0.12/lb. (Milling and Baking News)
HFCS: 33.33 lb./bu., 55% HFCS (dry weight), $0.20/lb. (Milling and Baking News, March 22, 1994)


CORN
WET MILLING
DRY MILLING
CLEANING
CLEANING
HEAVY STEEP WATER
STEEPING
GRINDING
MILLING
GERMS
GERMS SEPARATION
GRINDING
FIBER
FILTRATION WASHING
GLUTEN
GLUTEN SEPARATION
STARCH
LIQUEFACTION
LIQUEFACTION
SACCHARIFICATION
SACCHARIFICATION
FERMENTATION
CO2
FERMENTATION
YEAST
YEAST RECYCLING
WASTE WATER
DISTILLATION DEHYDRATION
ALCOHOL
DISTILLATION DEHYDRATION
DWG
CENTRIFUGATION
THIN STILLAGE
DRYING
EVAPORATORS
DDG/DDGS
SYRUP